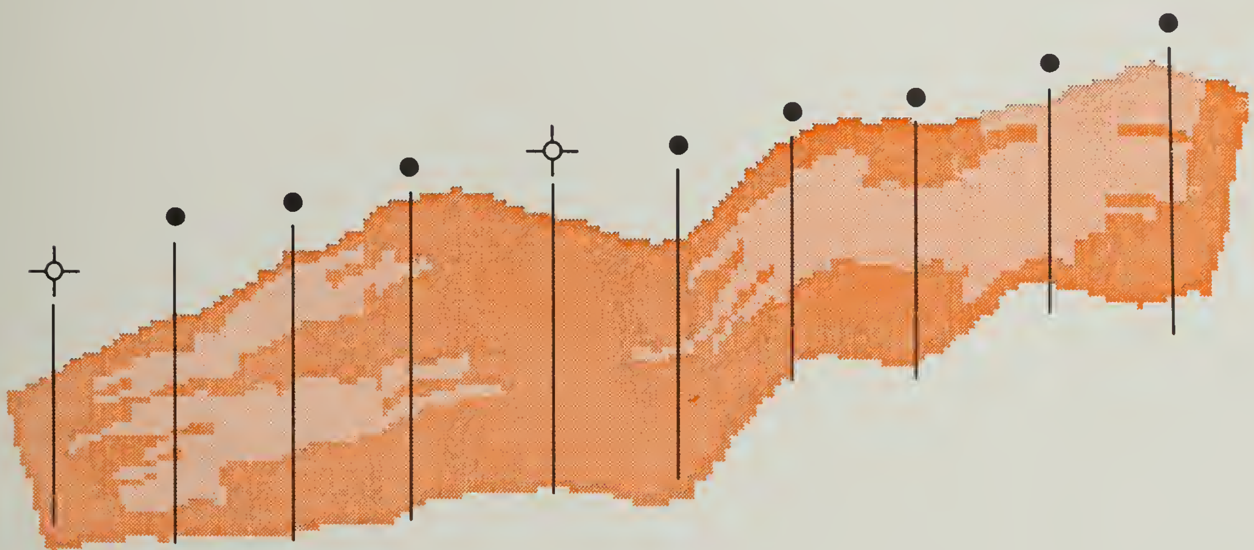
Geol Survey

An Integrated Geologic and Engineering Study of the Plumfield Lease Aux Vases Reservoirs, Zeigler Field, Franklin County, Illinois

Steve K. Sim, Beverly Seyler, Emmanuel O. Udegbunam



Illinois Petroleum 146
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Department of Energy and Natural Resources
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ABSTRACT

The number of well abandonments in Illinois since 1987 has increased threefold. One reason for the increase is difficulties encountered in waterflooding small heterogeneous reservoirs. This study describes the development strategies used in a successful waterflood project in the Plumfield lease at Zeigler Field in Franklin County, Illinois. These strategies could be applicable to similar reservoirs.

The Plumfield lease produced approximately 2 million barrels of oil during the past 29 years. The reservoir zone is in the Mississippian Aux Vases Formation and comprises three slightly overlapping and narrowly connected offshore marine sandstone bars.

Reservoir management strategies used at the Plumfield lease included obtaining cores from almost every well, bottom-hole pressure surveys, and production and injection surveillances. Bottom-hole pressure surveys and production and injection surveillances were used to locate permeability barriers, essential knowledge for optimum placement of water injectors in the field. The extensive core analyses showed whether reservoir intervals existed, and the reservoir porosity, permeability, and residual fluid saturations. Data from the core analyses were very important in defining flow units within the reservoirs in the Plumfield lease.

The waterflood performance of the Plumfield lease at Zeigler Field was evaluated using an integrated three-dimensional geologic and reservoir simulation model. A two-layer model was used to characterize the distribution of porosity, permeability, and fluid saturations in the reservoirs. Estimates from reservoir analyses showed that the Plumfield lease contained 4.56 MMSTB (million stock tank barrels), of which 43.07% was produced between June 1963 and February 1992. Simulation of another reservoir management scenario in which water injectors were placed at the onset of oil production showed a recovery of 1.05% more oil than the historical case. The predicted ultimate oil recovery factor without waterflood was 23%.

Reserve calculations indicate that about 57% of the original oil in place (OOIP) was bypassed at the Plumfield lease and that 14% of the remaining OOIP is moveable. The results of the reservoir simulation indicate the bulk of the recovered oil was produced from the upper, more permeable sand.

Future development opportunities at Plumfield should include improvement of sweep efficiency with polymers or cross-linked polymers and use of microbial enhanced oil recovery techniques. Targeted infill drilling, as part of an improved oil recovery project, should also be considered if economically feasible. Field-wide tracer tests or other tests to define flow units are strongly recommended to identify various scales of heterogeneities not detected by previous reservoir management programs in the field. The information gathered will provide a better understanding of the reservoir architecture and show the best ways to recover the remaining oil through improved recovery techniques.

Oil recovery during waterflood in this lease is relatively high for the Aux Vases Formation and attributable to the good reservoir management practices by the operator.

INTRODUCTION

Zeigler Field is in the southern half of Franklin County, in the south-central part of the Illinois Basin (fig. 1). Although Zeigler Field consists of several leases, only the Plumfield lease is considered in this study. Since its discovery in 1963, the Plumfield lease has produced close to 2 million barrels of oil from the Mississippian Aux Vases Formation sandstone reservoir intervals (fig. 2). The reservoir covers 500 acres and contains 30 productive wells on a 10-acre spacing. The Plumfield reservoir is near the end of the waterflood recovery stage. Most of the wells in this reservoir have been abandoned since the mid-1970s because of their high water cuts.

Figure 1 Location of Zeigler Field, Franklin County, Illinois.

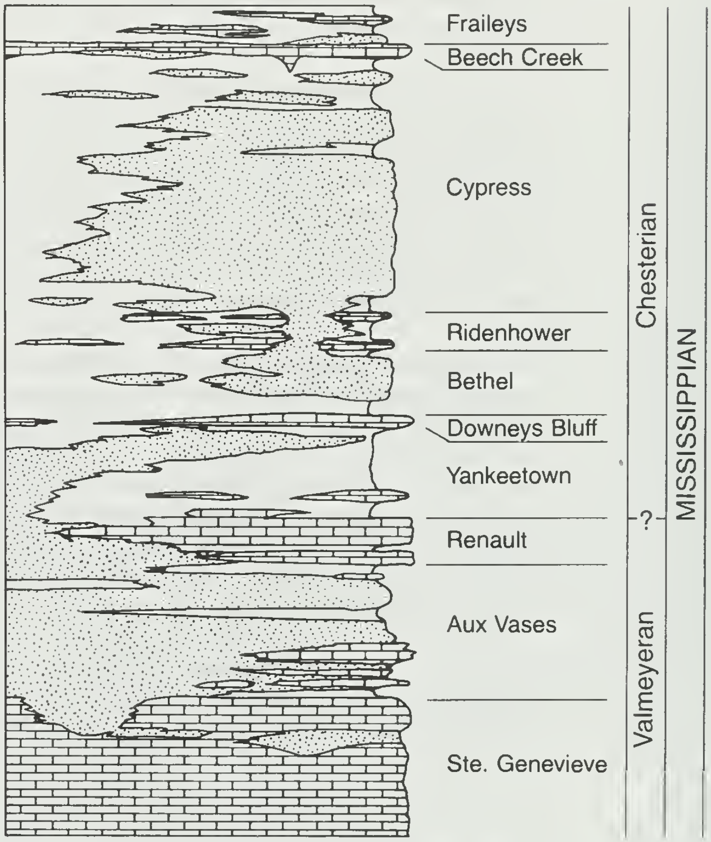


Figure 2 *right* Generalized stratigraphic column for upper Mississippian rocks in southern Illinois.

Nearly all the wells were cored during drilling. Porosity and permeability values were determined for more than 90% of the core samples. Spontaneous potential (SP) resistivity logs were also available for most wells. Oil and water production data, as well as water injection data, were recorded monthly for each well. Five pressure surveys of the oil-producing wells in the Plumfield lease were performed between January 1966 and January 1969.

Fields that produce from the Aux Vases Formation are noted for poor oil recovery during waterflood. Poor oil recovery is generally caused by reservoir compartmentalization and heterogeneity. The Plumfield lease, a combination of the West Plumfield, Plumfield, and South Plumfield leases, has a relatively high waterflood oil recovery factor despite compartmentalization and heterogeneity. This success is attributed mainly to prudent reservoir management by the operator. By gathering the necessary laboratory and field information during development of the lease, the operator was able to make timely reservoir management decisions to anticipate and overcome problems caused by reservoir heterogeneity.

This study uses the Plumfield reservoir to demonstrate the value of acquiring and using geological, engineering, and field data for reservoir management. The abun-

dant core analyses from Plumfield provided useful information for constructing an integrated geological and engineering reservoir model. Simulation shows that the operator's careful management of the Plumfield lease resulted in a cumulative oil recovery far above the average for most Aux Vases reservoirs. The study also uses the model to (1) estimate the oil recovery factors to date and the amounts of remaining OOIP (table 1) and unrecovered mobile oil, and (2) evaluate future development opportunities for the Plumfield lease.

Table 1 Nomenclature used in the report.

°API	= oil degree API gravity	PI	= productivity index
bbl	= barrel	psia	= pounds per square inch absolute
BOPD	= barrels of oil per day	psig	= pounds per square inch gauge
B_g	= gas formation volume factor (cf/scf)	PVT	= pressure–volume–temperature
B_o	= oil formation volume factor (rb/stb)	q	= flow rate (bbl/day)
CDF	= cumulative density function	R_c	= resistivity of adjacent shale bed (ohm-m)
cf	= cubic feet	R_s	= solution gas–oil ratio (scf/stb)
cp	= centipoise	R_t	= formation resistivity (ohm-m)
DST	= drill stem test	rb	= reservoir barrel
EDR	= estimated damage ratio	ROIP	= remaining oil in place
GOR	= gas–oil ratio	Sw	= water saturation (%)
h	= net pay thickness (ft)	scf	= standard cubic feet
$J(S_w)$	= Leverett J function	SP	= spontaneous potential
k	= permeability (md)	stb	= stock tank barrel
ln	= natural logarithm	T	= temperature (°F)
md	= millidarcy	t_p	= cumulative flowing time (days)
OOIP	= original oil in place	T_r	= reservoir temperature (°F)
P	= pressure (psia)	V_{DP}	= Dykstra–Parson heterogeneity index
P_c	= capillary pressure (psia)	V_{sh}	= volume of shale
P_i	= initial pressure (psia)	W(r,R)	= weighing function
P_o	= bubble-point pressure (psia)	μ	= viscosity (cp)
P_{wf}	= well flow pressure (psia)	ϕ	= porosity (%)
P_{ws}	= shut-in bottom-hole pressure (psia)		

FIELD HISTORY

Production History

The discovery well in the Plumfield lease, Plumfield no. 1 (P1, fig. 3), was completed in the spring of 1963 by Gallagher Drilling Company. Production began in June 1963 at an initial rate of 237 barrels of oil per day (BOPD). During the following 6 months, eight more wells (P2–P7, P9, P10) were drilled and completed. The total production rate of the nine wells in December 1963 was 571 BOPD (event 1, fig. 4). More wells were developed during 1964 in the West Plumfield and South Plumfield leases. By December 1964, 27 wells were producing at the rate of 645 BOPD. At peak production in the study area, 30 oil-producing and water injection wells were active.

Pressure Maintenance History

By the spring of 1965, the pumping rate at the Plumfield no.1 (P1) well had decreased from the initial rate of 237 BOPD to 11 BOPD. Reservoir pressure decline was precipitous, falling below 50 psig (pounds per square inch gauge) from an original reservoir pressure of about 1250 psig.

The injection of water started in February 1965 when four of the lower producers, West Plumfield no. 3 (WP3), West Plumfield no. 10 (WP10), Plumfield no.12 (P12) and Plumfield no. 20 (P20), were converted into water injectors (event 3, fig. 4). As a result, the declining field production rate and declining pressure were reversed. As more oil producers were shut in because of excessive water cut, some were converted into water injectors. By 1979, only six wells, producing a total of 28 BOPD, continued to pump oil (event 7, fig. 4).

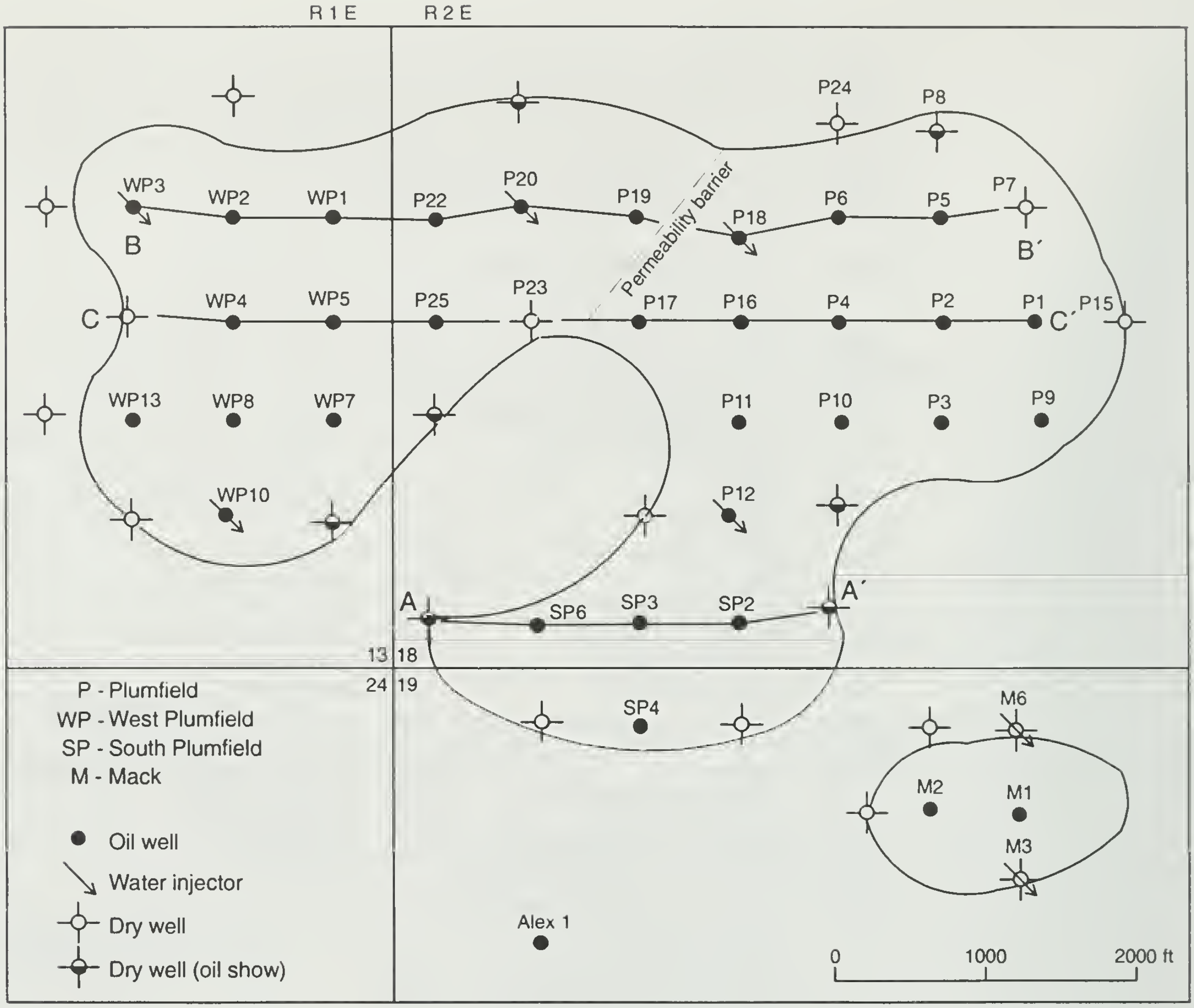


Figure 3 Well location map of Plumfield and Mack leases, Zeigler Field. Lines of cross sections A–A′, B–B′, and C–C′ are shown.

No peripheral water injectors were placed at the east end of the reservoir. The oil bank was swept eastward toward the stratigraphic pinch-out. This strategy worked well, as reflected by the high total oil production and delay of water breakthrough in the eastern peripheral wells, Plumfield no.1 (P1) and Plumfield no. 9 (P9) (fig. 3).

Historical Recovery Performance

As of February 1992, the total oil recovered from the Plumfield leases was 1,963,955 barrels. Given an estimated OOIP of 4.56 MMSTB (see section on Estimation of Reserves), the ultimate recovery factor to February 1992 was calculated to be 43.07% of OOIP.

RESERVOIR CHARACTERIZATION

Geological Description of Reservoirs at Zeigler Field

Depositional processes, mineralogy, and diagenesis affected the geometry, volume, connectivity, and composition of the Aux Vases Sandstone reservoirs at Zeigler Field. Brief discussions of these geologic characteristics and their effects on reservoir behavior follow. A detailed geologic description of Zeigler Field is presented in Seyler (in preparation).

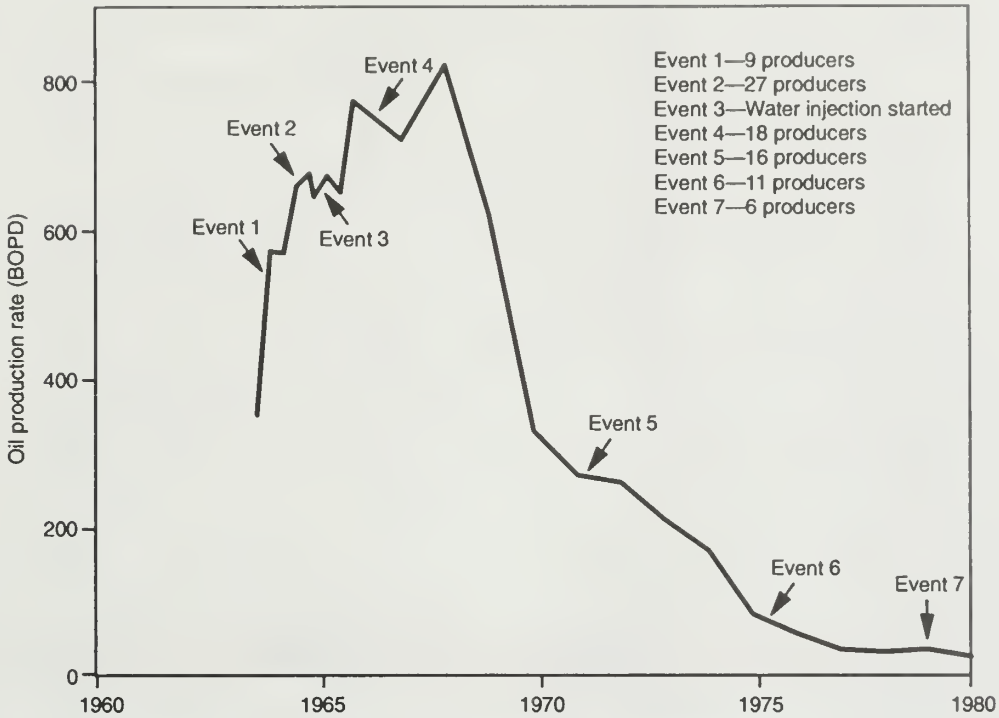


Figure 4 Oil production history of Plumfield lease.

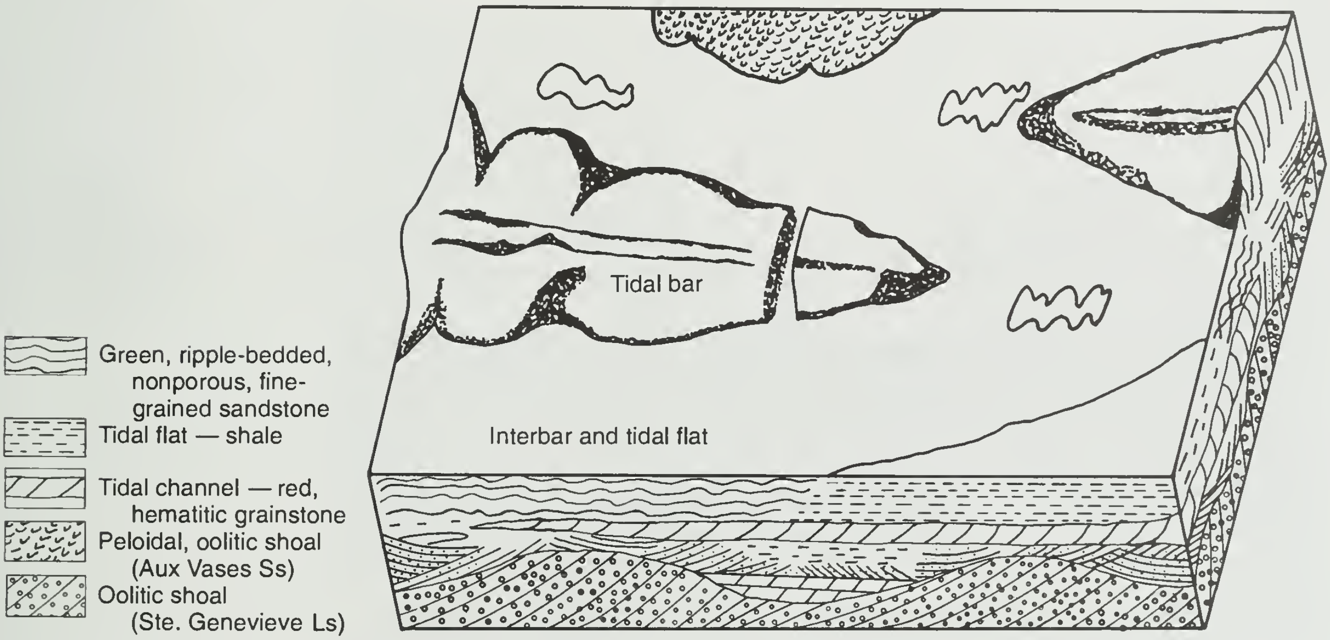


Figure 5 Conceptual geologic model depicts conditions leading to encasement of reservoir sandbars in reservoir-sealing units in a mixed carbonate–siliciclastic environment deposited by tidal processes.

Depositional processes The Aux Vases Formation at Zeigler Field was deposited in a mixed carbonate–siliciclastic environment by tidal processes. Figure 5 shows a conceptual geologic model for deposition of the reservoir and reservoir-sealing facies. Reservoir sandstone bars are effectively sealed by tidal-flat siltstones and shales at the top; by low energy, fine grained, ripple-bedded, nonporous sandstones and siltstones at the base; and by impermeable tidal-flat and and other low energy siltstones and fine grained sandstones laterally.

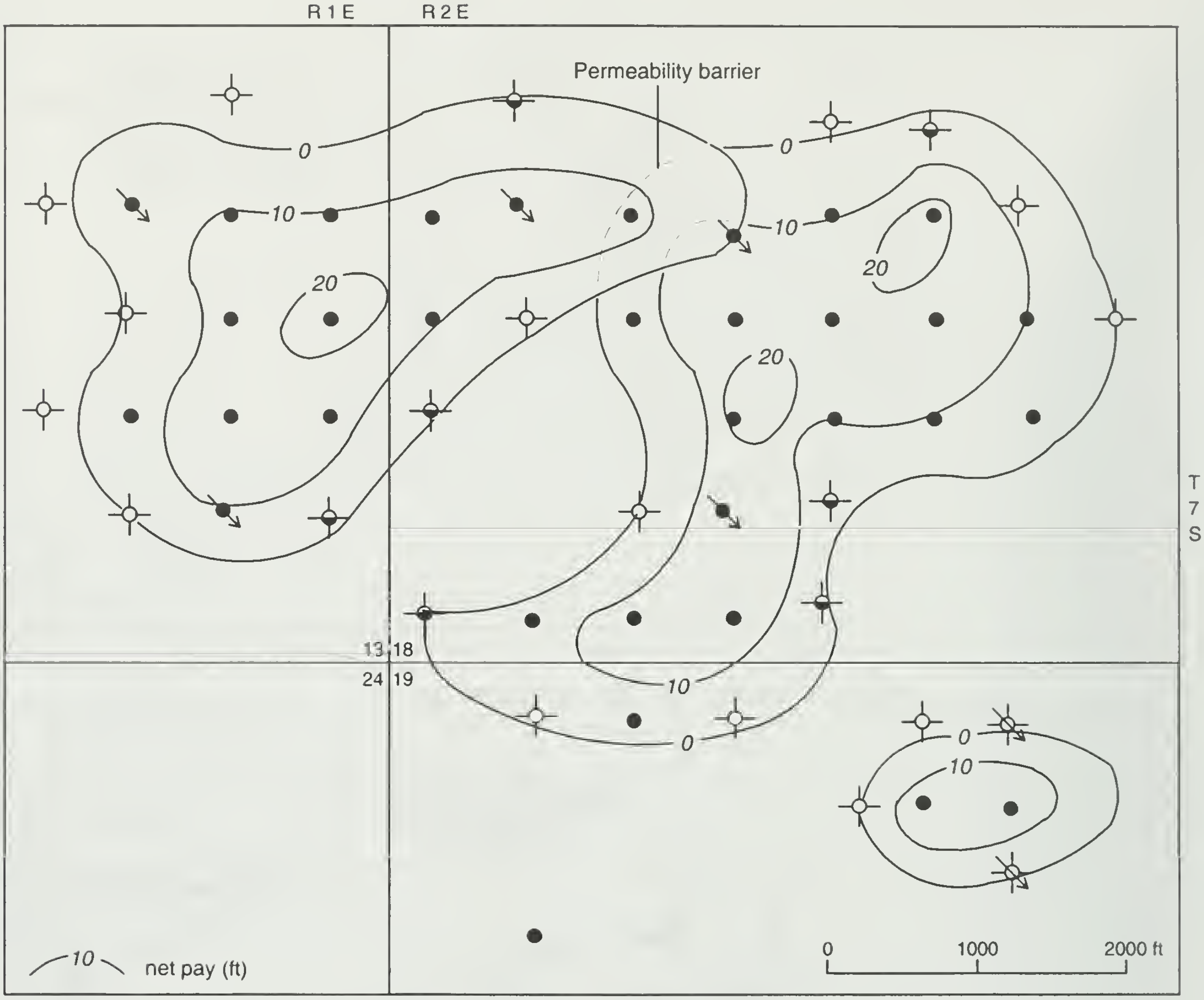


Figure 6 Contour map of net pay in the Plumfield and Mack leases.

Three sandstone bars, with varying amounts of interconnection, constitute the main body of Zeigler Field. These bars were also identified on the Plumfield lease in the main body of Zeigler Field (fig. 6). The sandstone bar on the west side of the field (West Plumfield) overlaps the bar on the east side of the lease (Plumfield), but no fluid communication exists between these two bars. At well P12 (fig. 3), the east Plumfield bar is narrowly connected with the sandstone bar in the south part of the lease, therefore fluid communication between these two bars is limited. The Mack lease consists of an isolated sandstone bar separated from the main body of Zeigler Field.

The bars are isolated from each other because of lateral depositional facies changes from porous sandstone to nonporous facies. Figure 7, a cross section (A–A′, fig. 3) of the South Plumfield lease, shows the convex-upward geometry of the sandstone bar.

Bottom-hole pressure surveys The existence of permeability barriers separating the three bars is more evident in pressure data than in correlations of electric logs or core descriptions. Surveys of bottom-hole pressures were used to confirm the existence of the permeability barrier that separates the east part of the field (composed mostly of the Plumfield lease) from the west part of the field (composed mostly of the West Plumfield lease). Figure 8 (B–B′, fig. 3), a west–east cross section

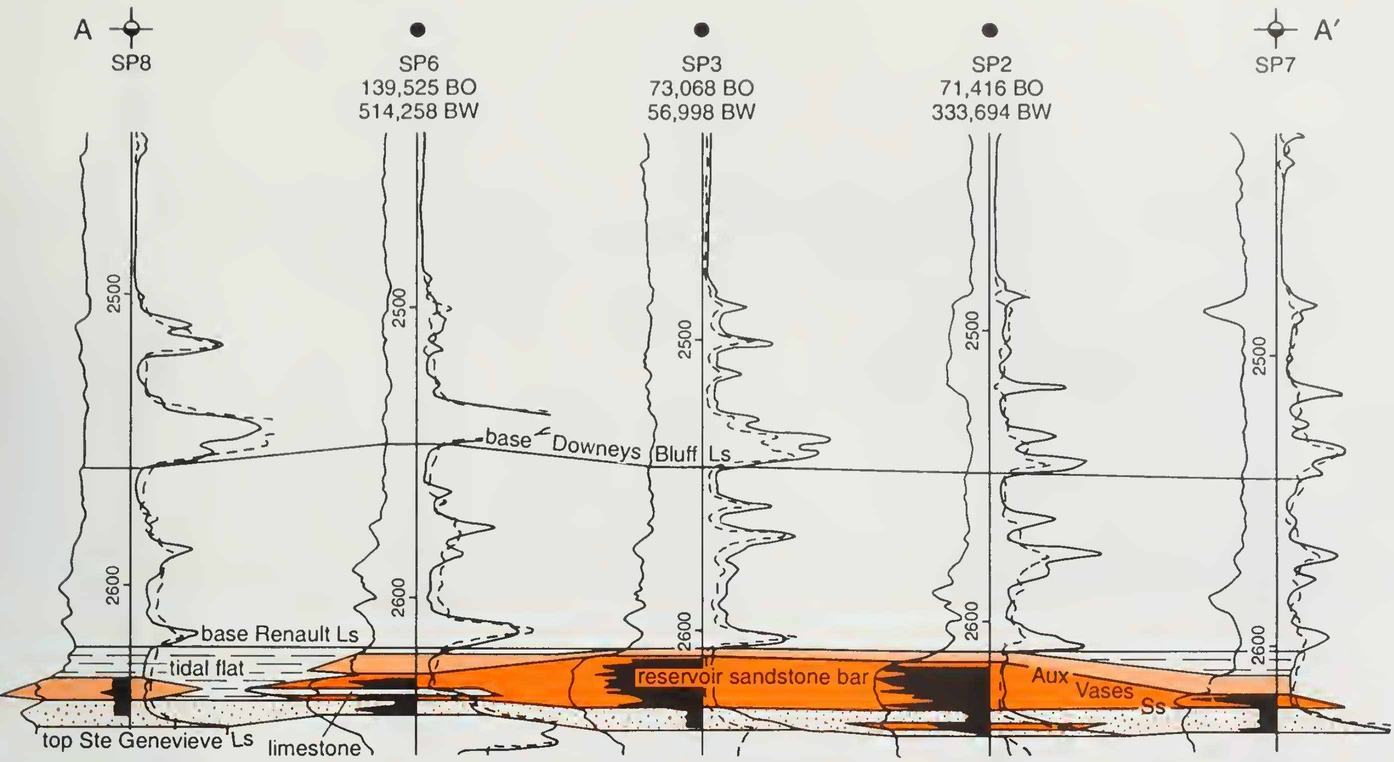


Figure 7 Cross section (A–A′) of South Plumfield lease shows the convex geometry of the sandstone bar. See figure 3 for line of section.

of the north part of the field, shows what appears to be a small, 2-foot shale break in the middle of the sandstone bar facies at the Plumfield no. 18 well. A pressure survey of the field (fig. 9) conducted in January 1966 showed a very large pressure differential between the west and east parts of the field near this location. This observation indicated that water injected into the west part of the unit did not affect oil production and reservoir pressures in the east part of the Plumfield lease. Knowledge of the existence and location of this permeability barrier led to the conversion of the Plumfield no. 18 (P18), located east of the permeability barrier, into an injection well. After 12 months of water injection, bottom-hole pressure at the Plumfield no. 17 well (P17) had risen from 149 psig to 951 psig (fig. 10). Information obtained from bottom-hole pressure surveillance conducted from 1966 through 1969 guided the strategic placement of injection wells, which were largely responsible for the relatively high recovery efficiencies attained in this field.

Trapping mechanism Zeigler Field is primarily a stratigraphic trap formed by sandstone bars that coincide with a slight structural saddle (fig. 11). The regional structure map of the top of the Ste. Genevieve Limestone shows no structural closure in the field.

Diagenesis The high porosities and permeabilities in this field are due mostly to the favorable effects of diagenetic events during lithification of the sandbars. Dissolution of feldspar grains led to the precipitation of diagenetic clay minerals. Porosities as high as 28% are common in these reservoirs because the diagenetic clay minerals that coat virtually every sand grain inhibited the precipitation of quartz overgrowths. In addition, large amounts of early calcite cement were dissolved in the thicker, central parts of the sandbars, further enhancing the porosity and permeability of the reservoir (Seyler in preparation). Pores lined with diagenetic clay minerals can cause significant problems during drilling, completion, and recovery programs (Haggerty and Seyler 1993). Diagenetic clay minerals can cause abnormally low resistivity readings on wireline logs; 2 ohm-meter deflections are very common at Zeigler Field (Seyler 1986). This phenomenon makes calculating water and oil saturations difficult.

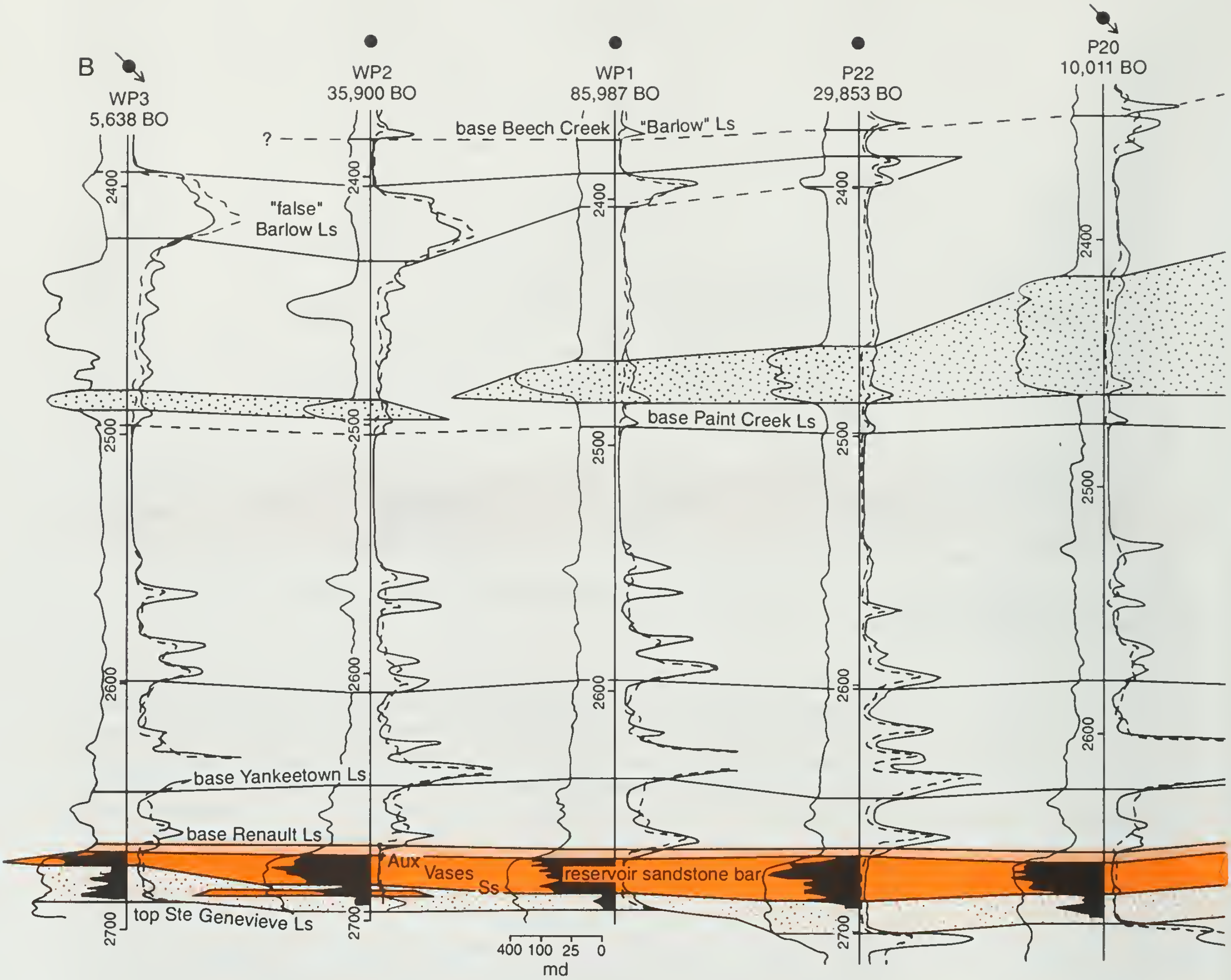
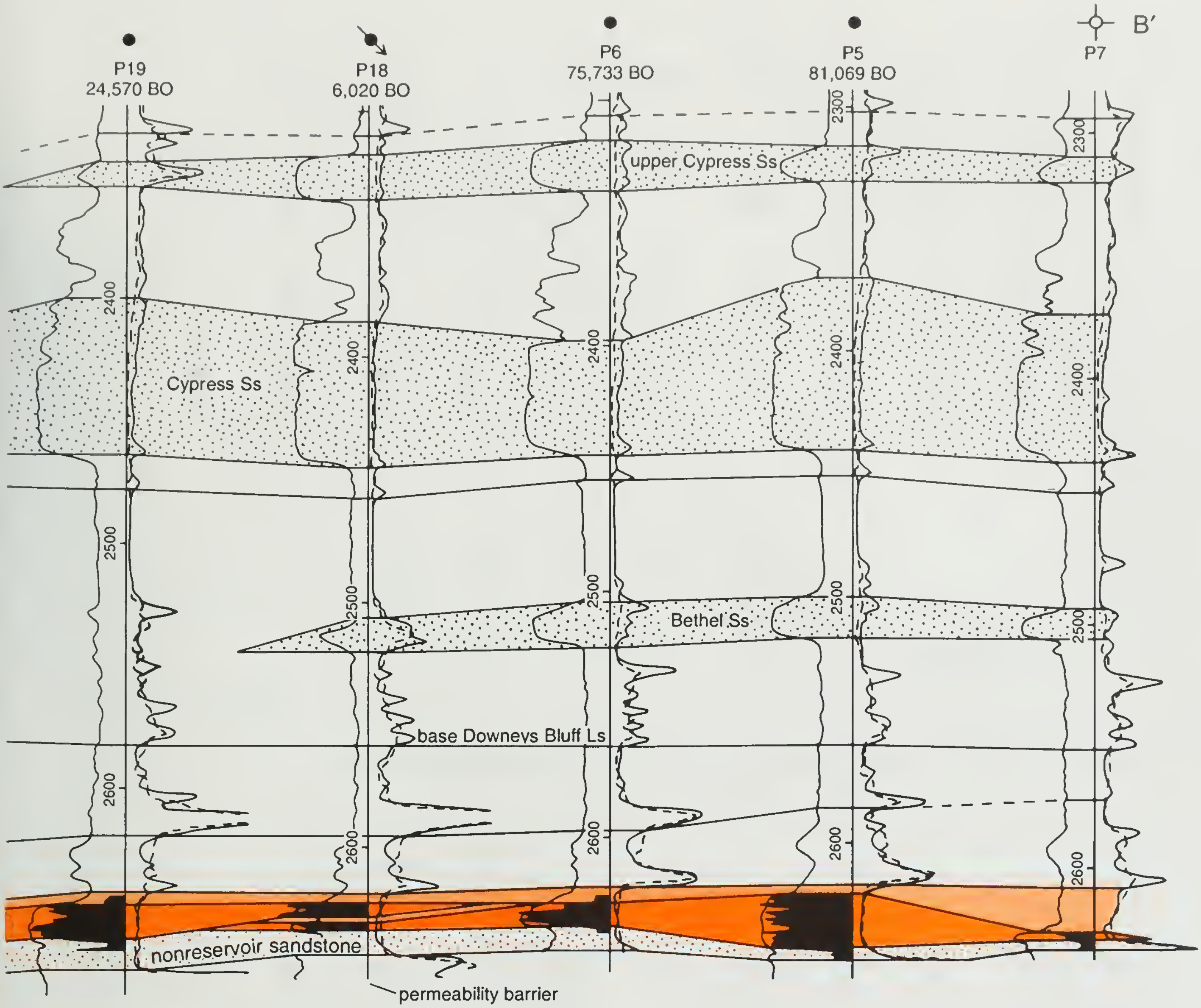


Figure 8 Cross section (B–B′) of the northern part of the West Plumfield and Plumfield leases. Reservoir sandstone bars possessing excellent to good porosity and permeability (graphed on the left side of logs) are encased in tidally deposited units

Reservoir Properties

Early in the development of the Plumfield lease, the operator conducted drill stem tests in selected wells, analyzed the pressure–volume–temperature (PVT) properties of an oil sample from the Plumfield no. 1 well (fig. 3), and analyzed cores from the producing interval. Bottom-hole pressure surveys and water injection surveillances were begun later to understand the performance of the water injection program. Consequently, large amounts of reservoir data are available to help characterize and manage the reservoir of the Plumfield lease.

Drill stem test data Data for a complete DST (table 1) of the Plumfield no. 1 well (P1) were provided by the operator. The data for the Plumfield no. 1 well were used in this study to demonstrate how DSTs can aid in reservoir characterization studies (table 2, fig. 12). Although DSTs are commonly conducted, many operators in the Illinois Basin do not take maximum advantage of the data.



that have minimal porosity and permeability. Location of permeability barrier was determined by pressure surveys and electric log signals. See figure 3 for line of section.

A DST is primarily designed to sample formation fluids and establish the possibility of commercial production. Data can also be used to determine reservoir pressures and several other reservoir characteristics, including well productivity, formation permeability, well bore damage, and the possible existence of permeability barriers, such as those formed by faults, pinch-outs, and facies changes (Lee 1982). To take full advantage of DST runs, the operator should be furnished with the test summary, as well as with pressure readings taken at consistent time intervals from the recorded pressure charts of a DST. Although many historical records do not include such detailed data, pressure readings from recent charts sometimes are available from the service companies that ran the tests.

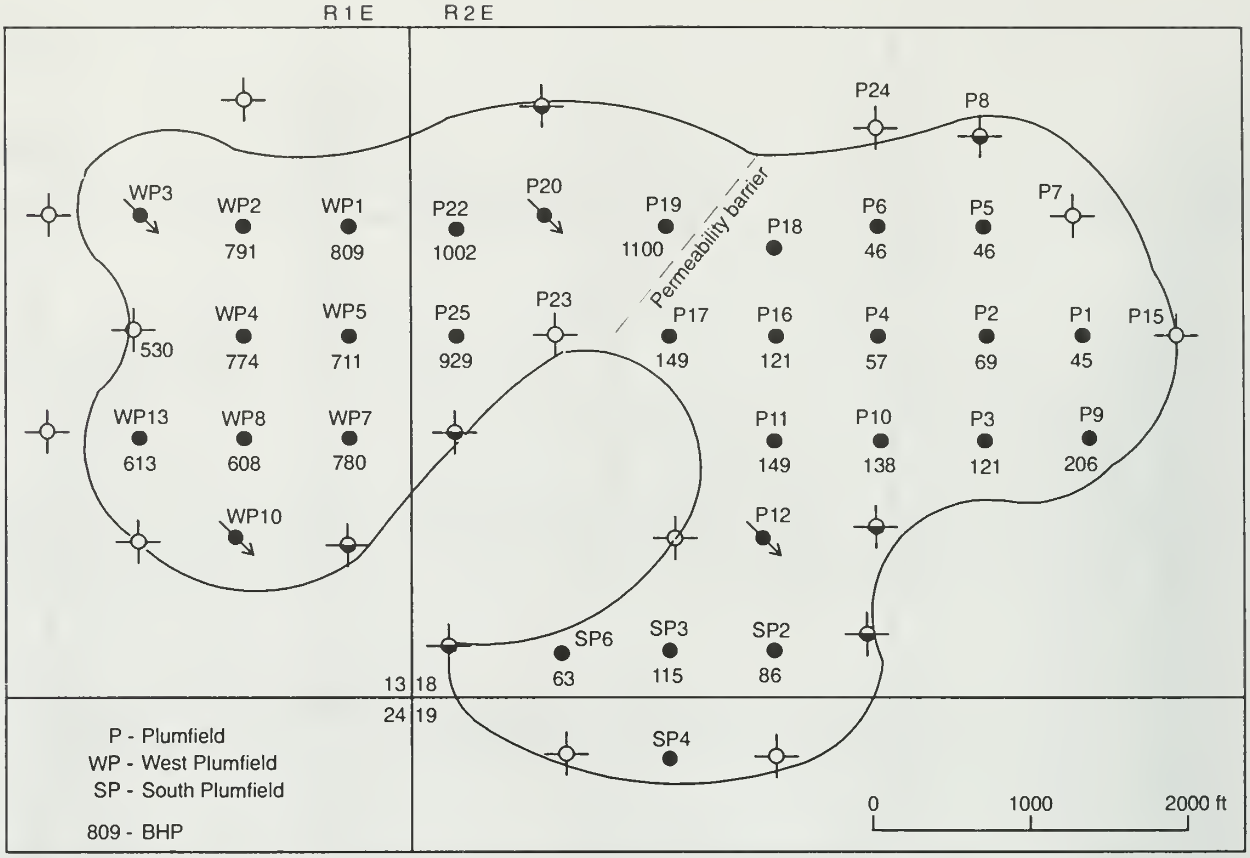


Figure 9 Distribution of bottom-hole pressure (BHP) in the Plumfield lease in January 1966.

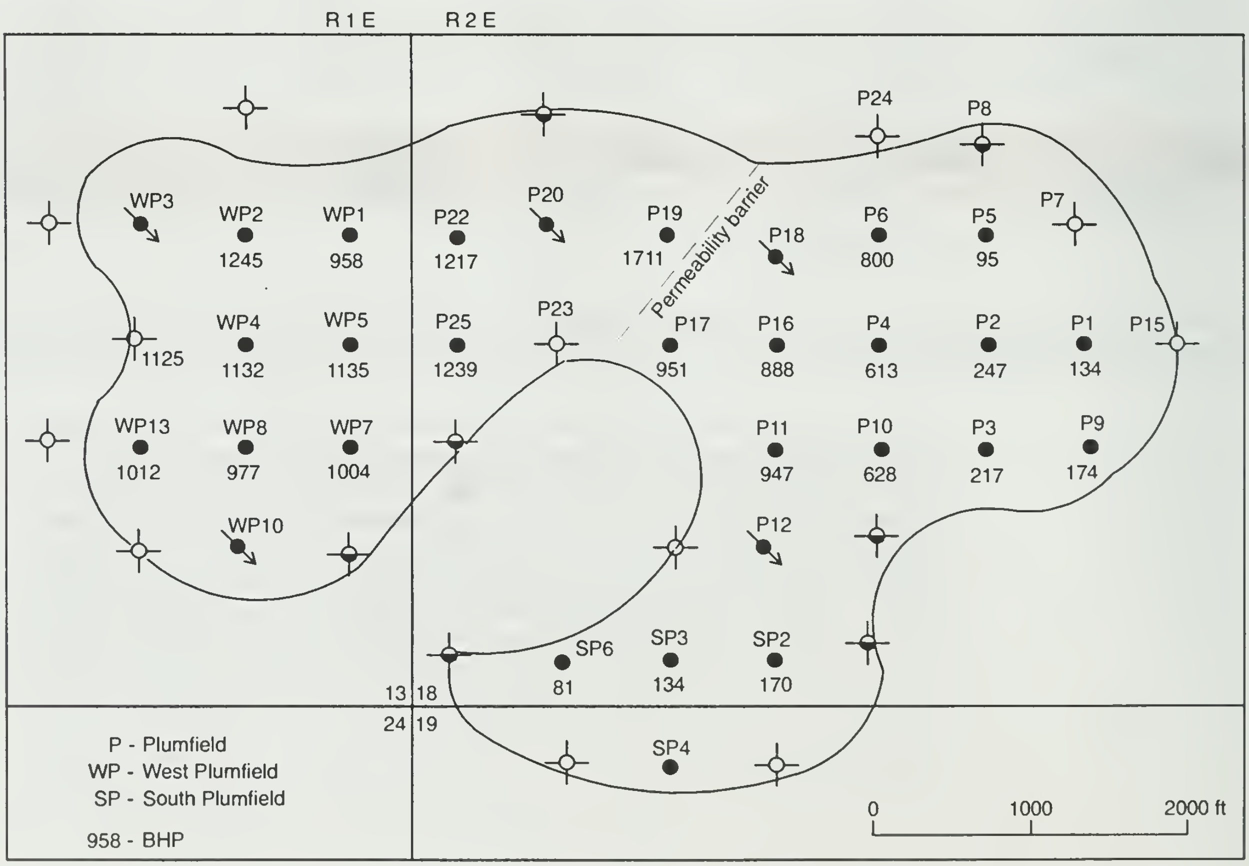


Figure 10 Distribution of bottom-hole pressure in the Plumfield lease in January 1967, after P18 was converted into an injection well.

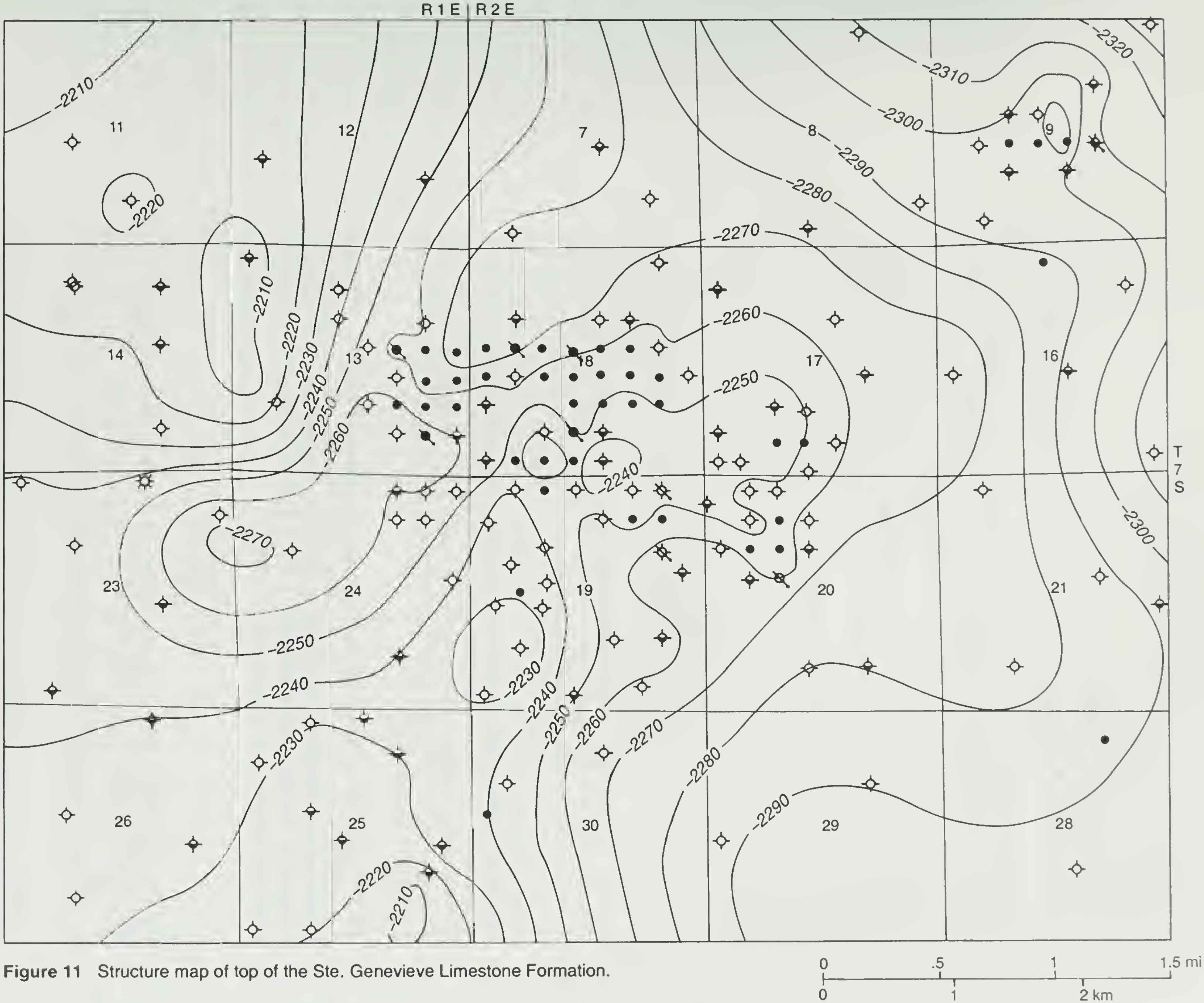


Figure 11 Structure map of top of the Ste. Genevieve Limestone Formation.

Table 2 Drill stem test of Plumfield no. 1 well.

Data summary
Interval tested: 2627–2640 feet, Aux Vases Formation
Drill pipe size: 4.5 inches
Initial flow period: 15 minutes
Initial shut-in period: 30 minutes
Final flow period: 45 minutes
Final shut-in period: 31 minutes

Reported recoveries
Liquid: 90 feet of mud-cut oil, 840 feet of oil (API = 38.9) during flow periods
Oil formation volume factor: 1.06 bbl/STB
Oil viscosity: 1.96 cp

Original reservoir pressure from drill stem tests Pressure buildup data from a DST are analyzed using equation 1 and Horner plot (fig. 12):

$$P_i - P_{ws} = 162.6 \frac{qB_o \mu}{kh} \log [(t_p + \Delta t)/\Delta t] \qquad [1]$$

where

t_p = cumulative flowing time (min)
Δt = time during shut in when each pressure is read (min)
P_i = original (static) reservoir pressure (psia)
P_{ws} = shut-in BHP recorded during DST (psia)
q = flow rate (BOPD)
B_o = oil formation volume factor (rb/stb)
μ = oil viscosity (cp)
k = formation permeability (md)
h = net pay thickness (ft)

Figure 12 shows a plot of the shut-in pressure, P_{ws}, against $\log(t_p + \Delta t)/\Delta t$ as expressed in equation 1. All the data points from the initial and final shut-in periods of this test are on a straight line, which has a slope of 140.44 psig/logarithmic cycle. The original reservoir pressure of 1,245 psig was determined by extrapolating the straight line to $(t_p + \Delta t)/\Delta t = 1$.

Effective in situ permeability and permeability–thickness product The in situ permeability of the reservoir in the drainage area of the well and the damage ratio (or skin) around the well bore may also be estimated using the information presented in figure 12. The slope (m) of the straight line in figure 12 is used to determine the in situ permeability from the following equation:

$$k = \frac{162.6\, qB_o \mu}{mh} \qquad [2]$$

Given that 840 feet of oil was recovered from the reservoir after a total flow time of 60 minutes through a pipe 4 1/2 inches in diameter, the oil flow rate is

$$q = \frac{(\text{drill–pipe capacity, bbl/ft}) \times (\text{liquid leg, ft}) \times (1{,}440, \text{min/day})}{(\text{flow period, min})} = 393.3 \text{ bbl/day} \qquad [3]$$

Substituting the values for Bo, m, and q = 403.2 bbl/day into equation 2, the in situ flow capacity (kh) is 946 millidarcies·feet (md·ft). The kh value determined from core analysis of the Plumfield no. 1 well is 924 md·ft, which deviates only 2.4% from the DST value of 840 md·ft. Given an average reservoir thickness of 13 feet, the effective in situ permeability is 76 md.

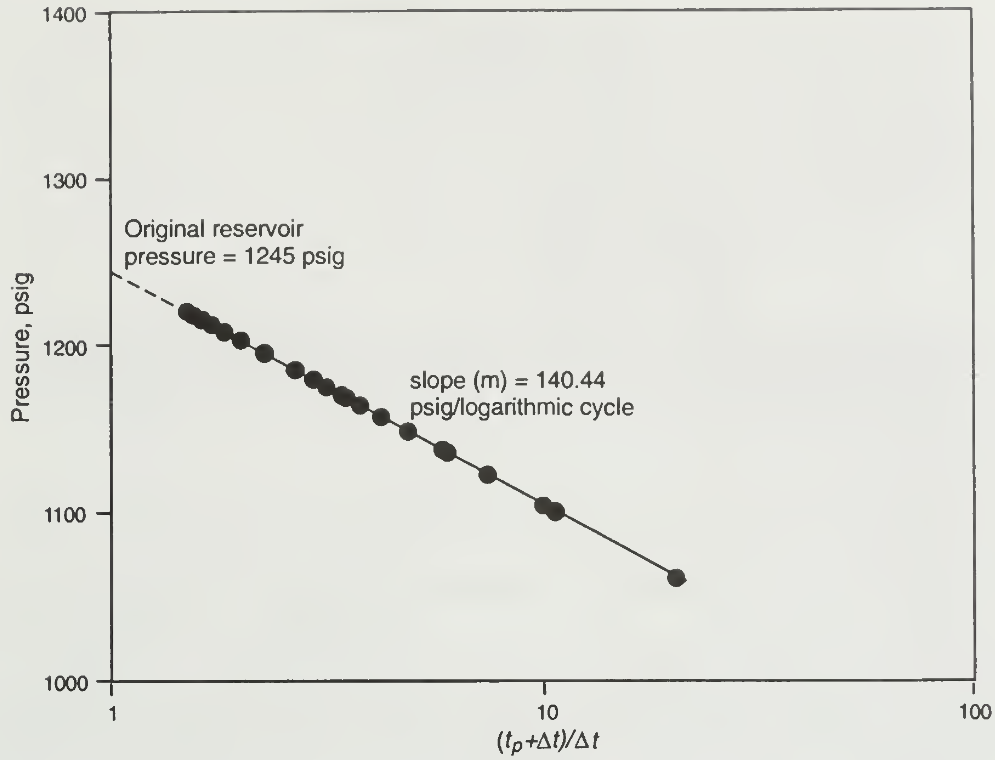


Figure 12 Horner plot for analysis of DST data from the Plumfield no. 1 well.

Estimated damage ratio The estimated damage ratio (EDR) also can be calculated from the DST data. The EDR value shows how much the productive capacity of the well would be increased had formation damage not occurred. In other words, the EDR informs the operator whether formation damage exists. It may also be useful for deciding whether to attempt to mitigate formation damage through treatments such as acidization or hydraulic fracturing. According to Reid (1983), the simplified equation commonly used by service companies is

$$\text{EDR} = \frac{0.183(P_i - P_{wf})}{m} \tag{4}$$

where

P_{wf} = flowing pressure (i.e., final flowing pressure, FFP)
m = slope of Horner plot = 140.44 psig/logarithmic cycle

For the Plumfield no. 1 well,

$$\text{EDR} = \frac{0.183(1245 - 222)}{140.44} = 1.33$$

This EDR value (1.33) implies that formation damage occurred and that the production capacity would be increased 1.33 times if the damage did not exist. Hence, instead of 393 bbl/day, the oil recovery rate during DST could have been as much as 524 bbl/day.

Determination of productivity index The results of a DST also can be used to estimate an oil well's productivity index (*PI*). The *PI* is used to forecast the long-term stable flow rate of a well and has an obvious economic significance in decision making. The stabilized *PI* equation is

$$PI = \frac{0.00708\ kh/\mu}{\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s} \qquad [5]$$

where

r_w = well bore radius (ft)
r_e = drainage radius (ft; taken as half the spacing unit)
s = skin factor = 7(EDR – 1) = 7(1.33 – 1) = 2.31.

When the values of kh/μ (from the DST), r_e, r_w, and s are substituted into equation 5, the stabilized PI for the Plumfield no. 1 well is 0.40 stb/day/psi. From this stabilized PI value, an operator can predict what the flow rate will be at a particular flow pressure, P_{wf}, using the following relationship:

$$q = \frac{PI \times (P_i - P_{wf})}{B_o} \qquad [6]$$

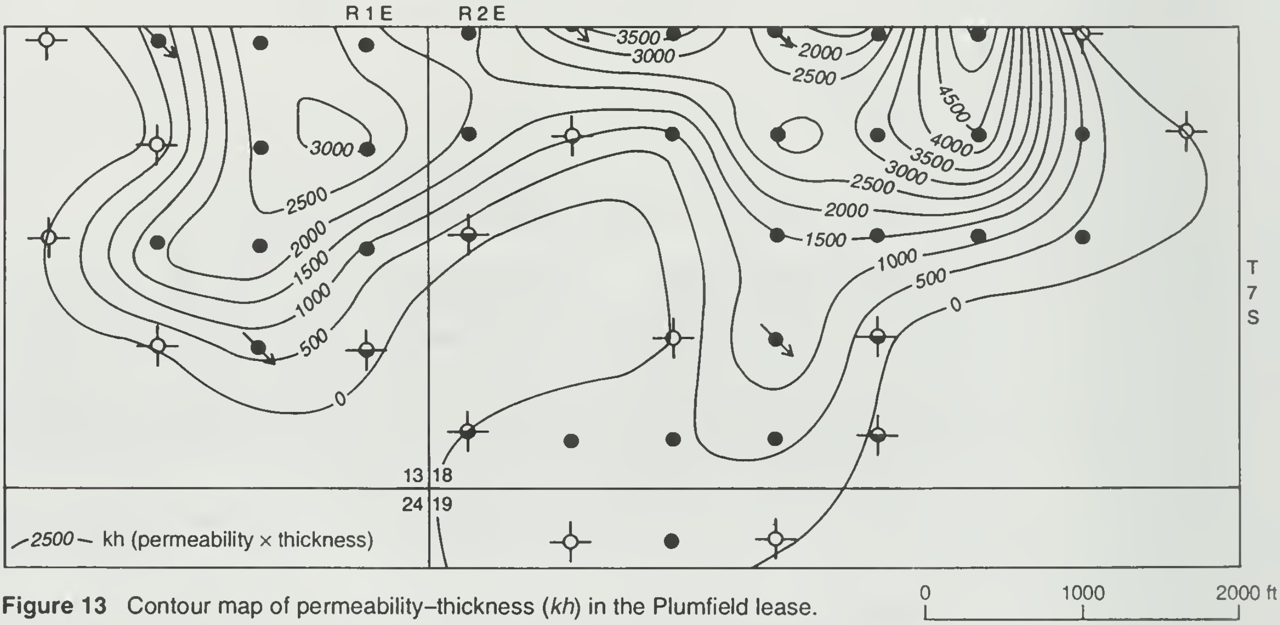


Figure 13 Contour map of permeability–thickness (kh) in the Plumfield lease.

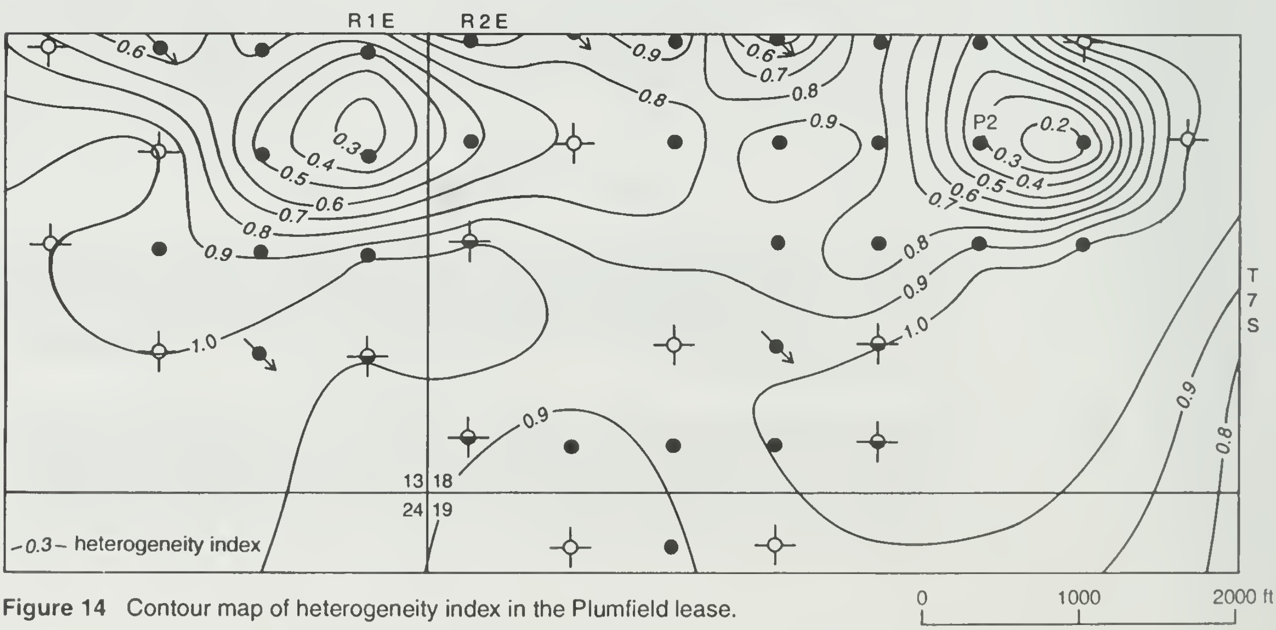


Figure 14 Contour map of heterogeneity index in the Plumfield lease.

In summary, DST results that include actual values of the pressure and time recorded by the pressure gauge are extremely useful for detailed analysis of the reservoir. As shown above, these data can be used to calculate original (static) reservoir pressure, in situ flow capacity (*kh*), effective permeability, estimated damage ratio, and productivity index for the reservoir at a given well location. These data are important for optimizing productivity of the reservoir. Drill stem tests also are used to sample formation fluids and establish the possibility of commercial production.

Trends of Reservoir Data in the Plumfield Lease

Analyses of 37 core samples from both productive and nonproductive wells in the Plumfield lease were used for this study. Zeigler Field as a whole has the highest density (92.5%) of cored wells among all Aux Vases reservoirs in Illinois.

Core permeability and porosity values were approximated for each well. Porosity values ranged from 8% to 25.8%; the mean value was 18%. The average porosity of the oil-producing sandstone interval was 21%. Permeability values ranged from 2 md to 261 md; the mean value for the entire lease was 95 md. The mean permeability of the oil-producing sandstone interval in the study area was 119 md.

Figures 13 and 14 show the distributions of the permeability–thickness product (*kh*) and the Dykstra–Parsons heterogeneity index values, respectively, for the Plumfield lease. The Dykstra–Parsons coefficient (V_{DP}; Dykstra and Parsons 1950), a measure of the vertical heterogeneity of the formation, was calculated from the permeability cumulative distribution function (CDF) of the wells. The CDF is a statistical relationship for representing the probability of occurrence of random variables. The V_{DP} is 0 for a very homogeneous porous medium and 1 for a highly heterogeneous porous medium.

A typical plot of a permeability CDF is shown in figure 15. The contour maps (figs. 13, 14) show that the reservoirs are less heterogenous in the regions having higher

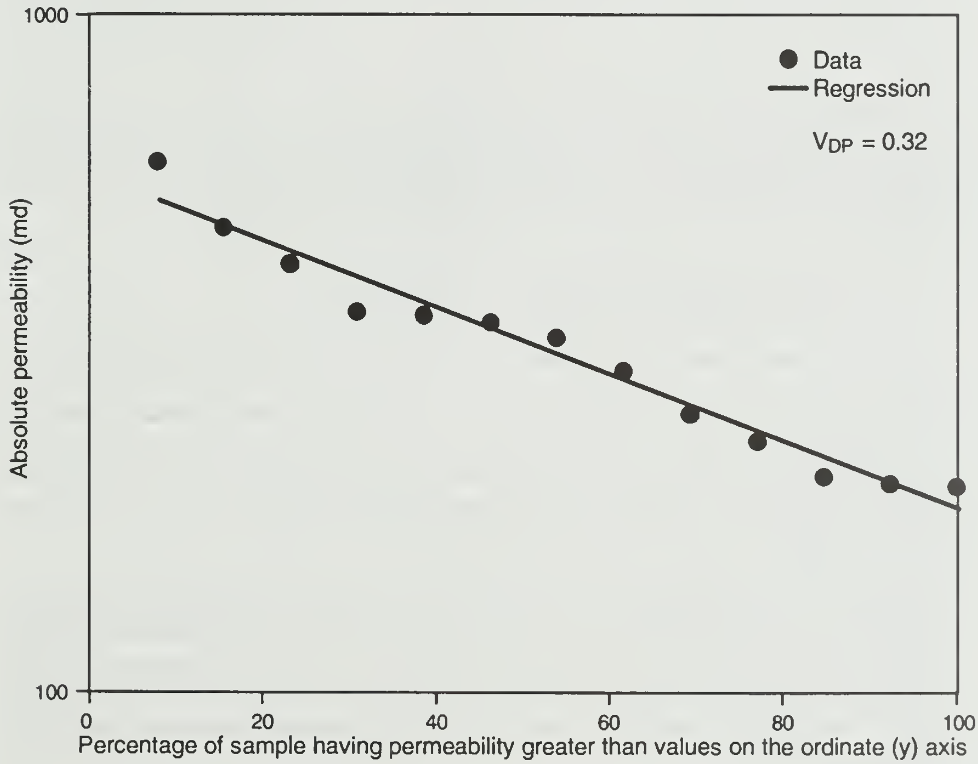


Figure 15 Cumulative distribution function of permeability in the Plumfield no. 2 well. The slope is the Dykstra–Parsons heterogeneity index (V_{DP}).

kh values. Poor vertical sweep efficiency is more likely to occur in areas with higher Dykstra–Parsons coefficients. The V_{DP} in the Plumfield lease ranges from 0.20 at the center to 1.0 at its periphery or boundary; the mean is 0.8, and the standard deviation is 0.24. The Plumfield lease field may be classified as "moderately heterogenous" (Dykstra and Parsons 1950).

Table 3 (Lake 1992) compares average reservoir properties of the Aux Vases Sandstone of the Plumfield lease with similar data from other major producing units in the United States. It shows that the average vertical heterogeneity within the Aux Vases Formation at the Plumfield lease is within the range found in other producing reservoirs in the United States.

Table 3 Average permeability (k) and porosity (ϕ) of some producing formations.[a]

Field name	Formation	Wells sampled	Mean k (md)	Mean ϕ	Mean V_{DP}
El Dorado	Admire	262	370.14	0.254	0.697
Keystone	Cardium	67	15.15	0.106	0.653
Zeigler	**Aux Vases**	**37**	**95.00**	**0.180**	**0.800**
Carrington	Manville B	38	5.73	0.112	0.822
Madison	Bartesville	36	29.95	0.179	0.823
Pembina	Cardium	16	273.64	0.122	0.894
HamiltonDome	Tensleep	33	98.42	0.143	0.694
Rozet	Muddy	20	43.14	0.171	0.846
Recluse	Muddy	12	74.93	0.144	0.855
Ute	Muddy	8	62.14	0.179	0.758
Pitchfork	Tensleep	5	91.54	0.141	0.723

[a] Modified from Lake (1992).

Hydrocarbon PVT properties The results of a partial PVT analysis of an oil mixture from the Plumfield no.1 discovery well were reported by Oilwell Research Inc. of Texas in April 1964. The oil gravity was 38.5° API, and the laboratory gas gravity was 0.928. This analysis, performed on a recombined oil sample prepared from 128 scf/stb (standard cubic feet of gas per barrel of stock tank oil), yielded an oil formation volume factor (B_o) of 1.074 rb/stb at a bubble-point pressure of 489 psig. The major uncertainty was the gas–oil ratio (GOR). The separator GOR was 141 scf/stb at 60°F; the estimated gas specific gravity was 1.25 (air = 1.0). The GOR was corrected, however, to correspond to the gas specific gravity value of 0.928 observed in the laboratory. The average oil formation factor estimated from the data of 20 years of oil production, as of February 1992, is as follows:

total volume of stock tank oil produced = 1,963,955 STB
total volume of water injected = 5,270,212 bbl
total volume of water produced = 3,111,893 bbl
injected water not produced = 5,270,212 – 3,111,893 = 2,158,319 bbl

If the natural water production, water influx, and free gas saturation are assumed to be negligible (which is reasonable since the average reservoir pressure was above bubble point during most of the waterflood period), the unproduced injected water only served to replace the produced oil volume. Thus, B_o = unproduced injected water/ stock tank oil = 2,158,319/1,963,955 = 1.09896.

This value is the upper limit for the oil formation volume factor and agrees fairly well with the value of 1.074 rb/stb obtained for the recombined sample at a bubble-point pressure of 489 psig and 1.068 rb/stb at the original reservoir pressure of 1,200 psig. Consequently, an oil formation volume factor of 1.068 rb/stb and a bubble-point pressure of 489 psig were used as the starting, predevelopment values for the reservoir model.

Another PVT analysis performed recently in the ISGS PVT laboratory and an oil and gas mixture from the Aux Vases Formation at the Gallagher Alex no. 1, a new well drilled south of the Plumfield leases in Zeigler Field. The sample, which was recombined at a gas–oil mixing ratio of 200 scf/stb, yielded an oil formation factor of 1.138 rb/stb at a bubble-point pressure of 707 psig and a reservoir temperature of 95°F. Differential vaporization data were generated for this mixture. Measured values of the gas–oil mixing ratio were adjusted from 200 scf/stb to 124 scf/stb to establish the variation of some properties (GOR, B_o, viscosity, and B_g) needed for reservoir simulation. Figures 16 and 17 show the variations of GOR and B_o, respectively, with changes in saturation pressure at 95°F, as used in this study.

Initial water saturations Fluid saturation values from core analyses were reported for four wells in the Plumfield lease. Invasion of the core plug by the mud filtrate from the water-based drilling mud and expansion of the hydrocarbon phase during retrieval to the surface often render core-derived saturation values suspect. In this work, calculations of initial water saturations (S_w) from old electric logs were based on the Simandoux method (Mian 1992):

$$S_w = \frac{0.4\, R_w}{\phi^2}\left[\sqrt{\frac{5\,\phi^2}{R_t R_w} + \left(\frac{V_{sh}}{R_c}\right)^2} - \frac{V_{sh}}{R_c}\right] \qquad [7]$$

where

R_w = formation water resistivity(ohm-m)
R_t = formation resistivity (ohm-m)
V_{sh} = fraction of shale in formation
R_c = resistivity of adjacent shale layer (ohm-m)
ϕ = porosity of formation (fraction).

Values for R_t and R_c were determined from the well resistivity logs. The R_w values were measured from produced formation water (Demir 1993). Values for V_{sh} were estimated from x-ray diffraction (XRD) analysis. Porosity was obtained from core analysis reports of the wells.

Equation 7 gives initial water saturation values in the range of 30% to 79% in the oil-producing wells. These values are about 5% to 20% lower than those obtained from core analyses (fig. 18). Water saturation values measured during core analyses probably are consistently higher than those measured in the field because of the invasion of mud filtrates from water-based mud into the formation during drilling. Water saturation values obtained from core analyses are, therefore, higher than actual values. The initial water saturation values, obtained from equation 7, were used in the reservoir simulation modeling. The average initial water saturation of both the oil-producing and nonproducing intervals, as calculated by the reservoir simulator, is 48.9%. The estimated OOIP is 4.5 MMSTB, which is within the range of OOIP (4.3–5.0 MMSTB) calculated using the capillary pressure method described below.

Oil–water contact Use of the equlibrium (capillary pressure) approach to initialize the resevior simulation model requires knowledge of the elevation of the oil–water contact in the reservoir. No distinct oil–water contact could be detected from either wireline logs or core analysis. Even though the wells at Zeigler Field were completed open hole, no water production was observed during the period of primary production in the eastern and southern parts of the field, indicating that the producing intervals were well above the oil–water contact. Small and intermittent water production observed in the western part of the field during this time indicated that permeable porosity was present below the oil–water transition zone or the oil–water contact.

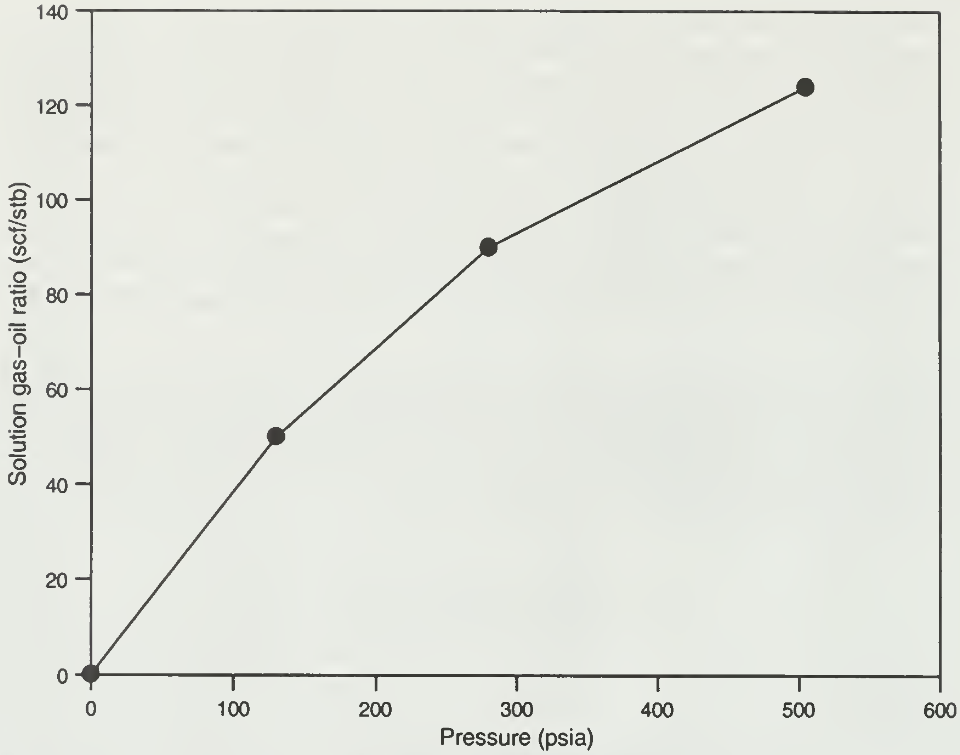


Figure 16 Variation of solution gas–oil ratio (R_s) with saturation pressure as determined by experimental PVT measurements on gas–crude oil mixtures from the Aux Vases Formation, Zeigler Field.

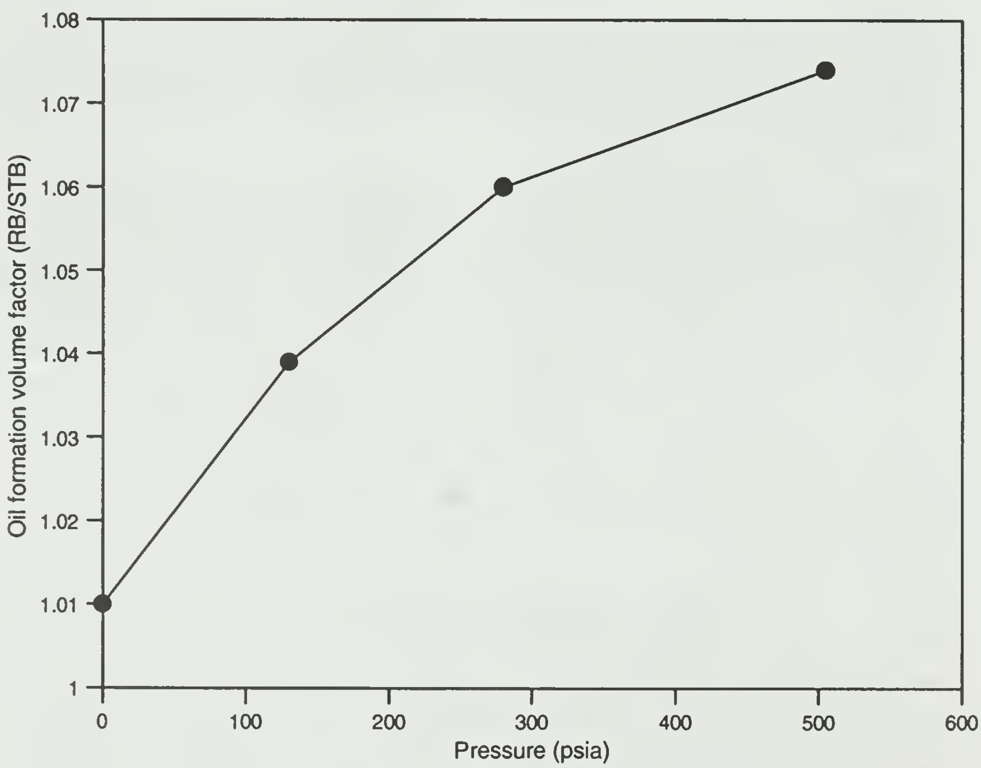


Figure 17 Variation of oil formation volume factor (B_o) with saturation pressure as determined by experimental PVT measurements on gas–crude oil mixtures from the Aux Vases Formation, Zeigler Field.

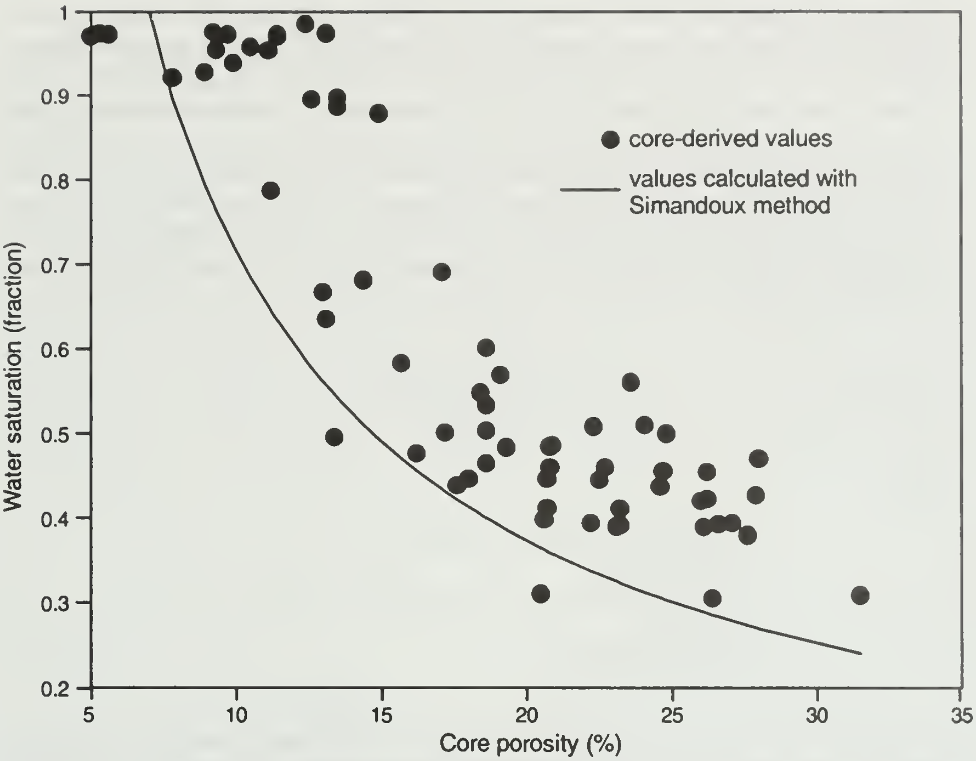


Figure 18 Comparison of core-derived water saturation values with calculated values.

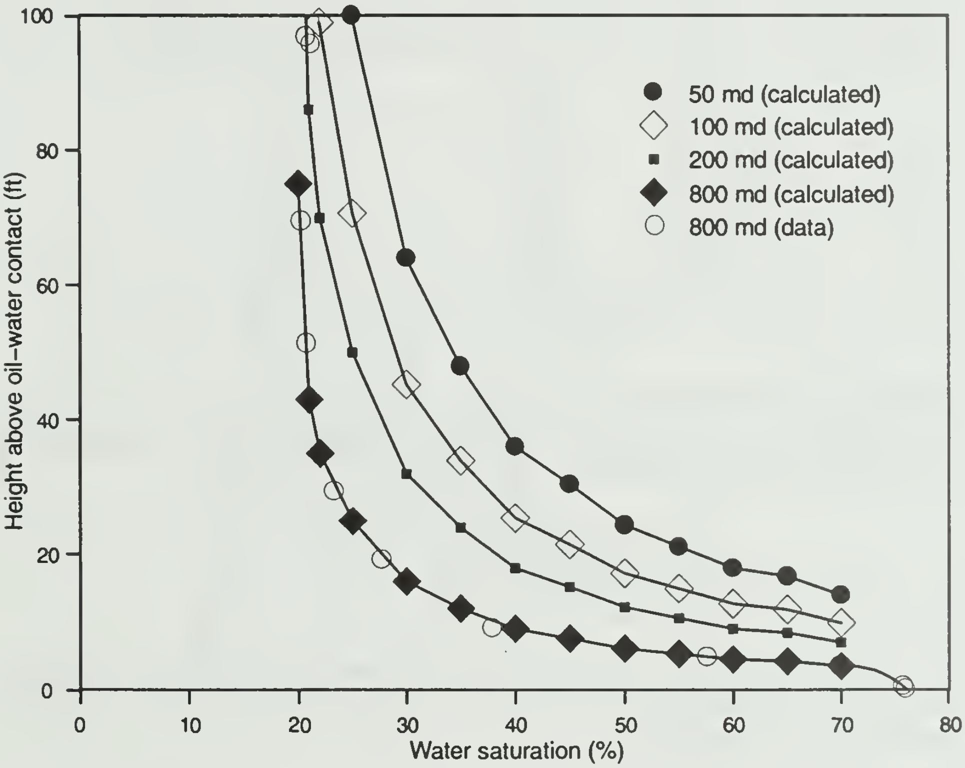


Figure 19 Relationship between capillary pressure and water saturation in the Plumfield lease as determined by Leverett (J) function for various permeability values.

An oil–water contact for the field was estimated from sensitivity analyses using capillary pressure data provided by the operator (fig. 19). This capillary pressure curve was obtained from a core sample that had an air permeability of 800 md and an irreducible water saturation of 20%. The permeability values of the productive intervals in the Plumfield lease were determined from core data and ranged from 100 to 200 md. The average irreducible water saturation was expected to be slightly higher in low permeability zones. The experimental capillary pressure data were normalized by using the Leverett (1941) $J(S_w)$ function (equation 8) and a series of new capillary pressure curves were generated for rock samples that had other permeability values.

$$J(S_w) = \frac{P_c}{\sigma \cos \Theta} \sqrt{\frac{k}{\phi}} \qquad [8]$$

where

σ = oil–water interfacial tension
Θ = contact angle
k = permeability (md)
ϕ = porosity
P_c = capillary pressure
S_w = water saturation

Table 4 shows the effect of the elevation of the oil–water contact on reserve estimates in the Plumfield lease. The elevation of the oil–water contact ranges from –2,266 to –2,291 feet depending on the permeability and porosity values.

Table 4 Original oil in place (OOIP) as a function of the oil–water contact (OWC) elevation and rock permeability.

Permeability (md)	OWC (ft)	OOIP (MSTB)	Overall recovery factor (%)
200	–2,266	4385.2	44.77
	–2,271	4734.8	41.47
	–2,281	5062.6	38.78
	–2,291	5125.2	38.31
100	–2,266	4158.6	47.22
	–2,271	4308.8	45.58
	–2,281	4852.4	40.46
	–2,291	5079.1	38.66

Estimation of Reserves

The average values for reservoir properties used in estimating the reserves in the Plumfield leases were as follows:

Reservoir volume = 6,825 acre-feet
Porosity (%; core analysis) = 18
Oil formation volume factor (rb/stb) = 1.068
Water saturation (%) = 48.9

The estimated OOIP is 4.56 MMSTB. This value differs from the operator's preliminary reserve estimate by 4.8% and yields an ultimate recovery factor of 43.07% after 29 years of production.

Geological Modeling

A three-dimensional geological model of the Plumfield lease was constructed using the Stratigraphic Geocellular Modeling (SGM^{TM}) computer software. This software subdivides the gross rock volume into many cells. Attributes that can be assigned

to the cells include lithology, porosity, permeability, and fluid saturation. Attribute values for each cell are estimated by the software from the petrophysical data for the wells. The process uses one of two interpolation schemes and a search radius specified by the user.

A detailed geological model of the Plumfield lease was created by generating surface grids of the top and base of the Aux Vases Formation (generated by the Zycor™ program) and by inputting all available reservoir attributes, such as permeability, porosity, lithology, and fluids saturations from 34 wells. The values of the attributes in each cell were determined by an interpolation scheme that depends on a search radius and power factors. Depending on the search radius and the power factor, a weighting function (W(r,R)) to be used for calculating interwell attribute values is determined, using either a deterministic or a statistical algorithm as shown in equations 9 and 10, respectively (Stratamodel Inc. 1991). The appropriate values of the search radius, weighting function, and power factors to use were investigated in this study by means of sensitivity tests.

$$W(r,R) = (1-r/R)^2(R/r)^x \quad \text{deterministic function} \qquad [9]$$

$$W(r,R) = (1-r/R)^2(1+2r/R)^x \quad \text{statistical function} \qquad [10]$$

where

R = search radius
x = power factor
r = distance from the interpolated point

Figure 20 compares core-derived permeability values for the West Plumfield no. 4 well (WP4) with the values calculated by SGM™ for various search radii using a power factor of 2 and a statistical algorithm. Although the absolute difference between the core-derived and calculated permeability values increases with the search radius, the mean deviation between the two was lowest for the search radius

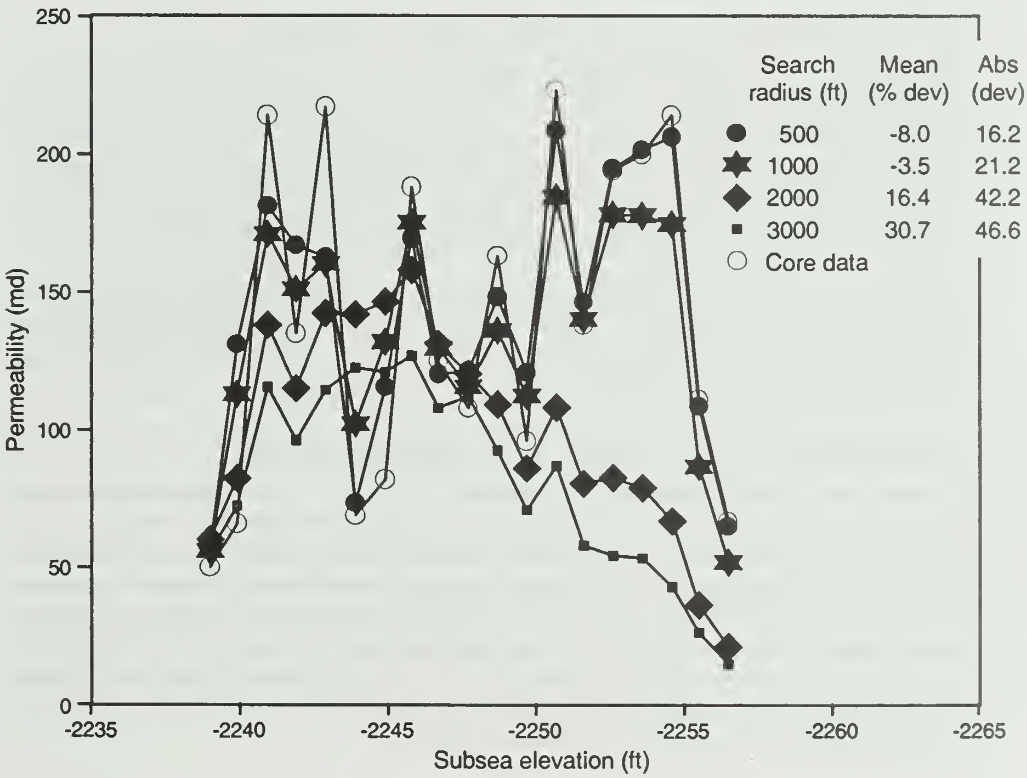


Figure 20 Comparison of core-derived permeability values with those determined by SGM™

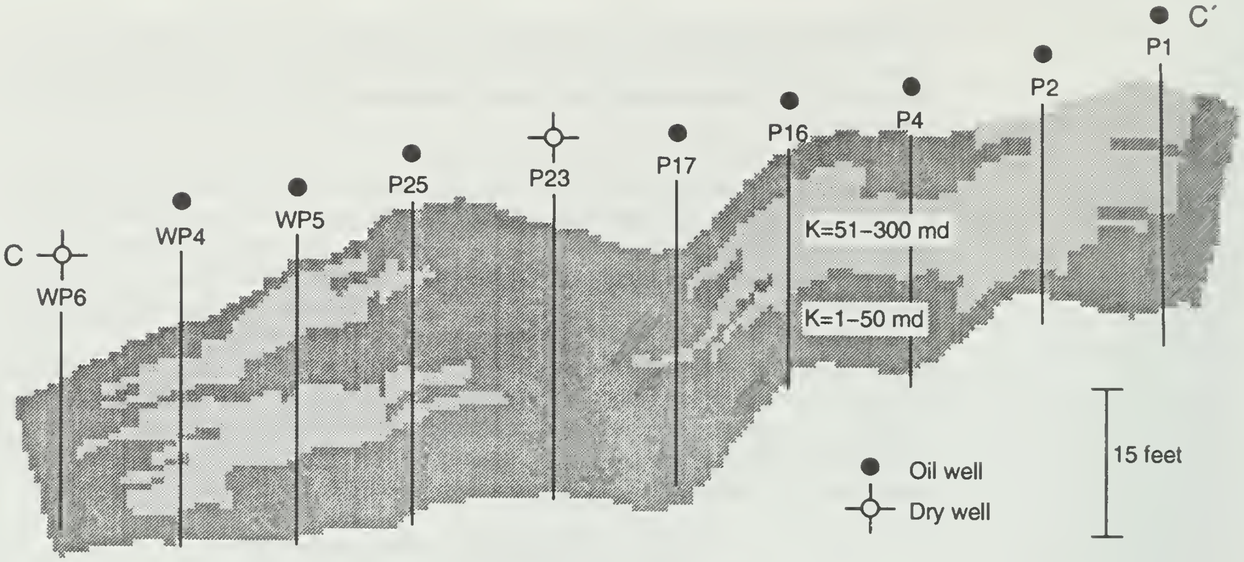


Figure 21 Permeability distribution of the cross section (C–C′) of West Plumfield and Plumfield leases. See figure 3 for line of section.

of 1,000 feet. Consequently, a search radius of 1,000 feet was used in this work. Furthermore, a search radius of 1,000 feet only permits data from neighboring wells that are within one well spacing (660 feet) of each other to be used in the calculation of interwell attributes. This observation is particularly important in formations for which reservoir attribute values vary over relatively small distances.

Figure 21 shows the permeability values for cross section C–C′ (fig. 3) and illustrates the absence of permeability continuity between the sandbars in the West Plumfield and Plumfield leases across the permeability barrier (fig. 9).

RESERVOIR SIMULATION

Gridblock Selection and Simulation Technique

Geological modeling was the basis for selecting a reservoir simulation consisting of two separate flow units. Permeability in the upper interval generally exceeded 50 md, whereas permeability in the lower interval generally was less than 50 md. The individual cell attributes were averaged arithmetically and exported to the reservoir simulator for subsequent model initialization. A three-dimensional grid system consisting of 48 × 33 × 2 cells and 3 grid cells between adjacent wells was built. Both two- and three-dimensional, full-field, implicit black-oil models were used to simulate the depletion of the Plumfield lease. The software used in this study was the Western Atlas Integrated Technologies VIP CORE™ simulator, licensed to the ISGS and operated on a Silicon-Graphics workstation. VIP's BLITZ solution technique was used to solve the algebraic equations.

Initialization of the Reservoir Simulation Model

The end-point relative permeability and water saturation values used in the simulation were obtained from two Aux Vases sandstone reservoirs in the South East Jordan School and Feller units, Wayne County, Illinois (Sandiford and Eggebrecht 1972). These are the only published relative permeability and water saturation values for the Aux Vases Formation in the Illinois Basin. The relative permeability values used in the simulation were then adjusted by an iterative process to obtain a good match with the oil and water production history for the field. Five oil–water relative permeability curves were used to obtain a reasonable match with the historical performance of 30 oil-producing wells.

History Match

Several history-match runs were necessary to ensure that the model closely simulated known field performance and to ensure its reliability for prediction. The reservoir simulation model was calibrated by matching histories of (1) monthly oil and water production values for the 30 selected wells and (2) reservoir pressures from a drill stem test (Plumfield no.1) and bottom-hole surveys.

Gas production records were not available. Necessary adjustments were made in the initial water saturation and relative permeability curves for oil–water and oil–gas to match the simulation results to the actual historical data.

The overall quality of the history match was good. Water cut and oil production matches were made for each well. The match between the simulated and actual data for water cut and oil production for the South Plumfield no. 2 well is shown in figure 22. The pressure match for the Plumfield no. 2 well (fig. 23) typifies the quality of the match obtained for the Plumfield wells for this parameter.

Waterflood Performance in the Plumfield Lease

As figure 24 shows, there is a good correlation between cumulative oil production and pemeability–thickness values (*kh*), except for wells with low *kh*. Some wells with low *kh* had very high cumulative oil production because of their location. Even though Plumfield no. 9 (P9), Plumfield no. 1 (P1), South Plumfield no. 6 (SP6), and West Plumfield no. 7 (WP7) wells have low *kh* values, their respective cumulative oil productions far exceeded the norm because the placement of water injection wells caused oil to bank near their locations. All four wells are bordered by impermeable lithologies.

The waterflood development of the Plumfield lease was also simulated. Two alternative scenarios, in addition to the historical development, were compared. In one scenario, no water was injected. The cumulative oil production from the Plumfield unit, in this case, was only about 23% of OOIP (compared with the historical ultimate oil recovery factor of 43%). In the second scenario, two nonproductive wells (P8 and P24, fig. 3) at the north flank of the Plumfield unit were used as injectors at the onset of oil production instead of after 1 year. In the actual development of the lease, water injection did not commence until 1 year after production start-up, when reservoir pressure and oil production rates had begun to decline precipitously. In effect, this case quantified the effect of the delay in implementing pressure maintenance. Simulation results (fig. 25) show a mere 1.05% improvement (42 MSTB) under the early water injection scenario, as compared with total historical oil production at the end of 1990.

Location of the water injection wells is quite important. Another run simulated the conversion to injectors of two other nonproducing wells, the Plumfield no. 7 (P7) and Plumfield no. 15 (P15), on the east flank of the Plumfield unit. This simulation did not result in a significant increase in cumulative oil recovery. The model indicated that this scenario would have caused earlier water breakthrough than was historically the case at Plumfield no. 1 (P1) and Plumfield no. 9 (P9), the most productive wells in the field.

The simulation calculations show less oil saturation remaining in the upper layer (oil recovery is 48.9%) than in the lower layer (oil recovery is 26.4%) (fig. 21). This finding suggests poor sweep of the lower sand interval in the model. The available evidence indicates that the upper sandstone interval is more permeable and probably more continuous than the lower interval. Consequently, the upper sandstone interval can be more efficiently swept than the lower sandstone interval.

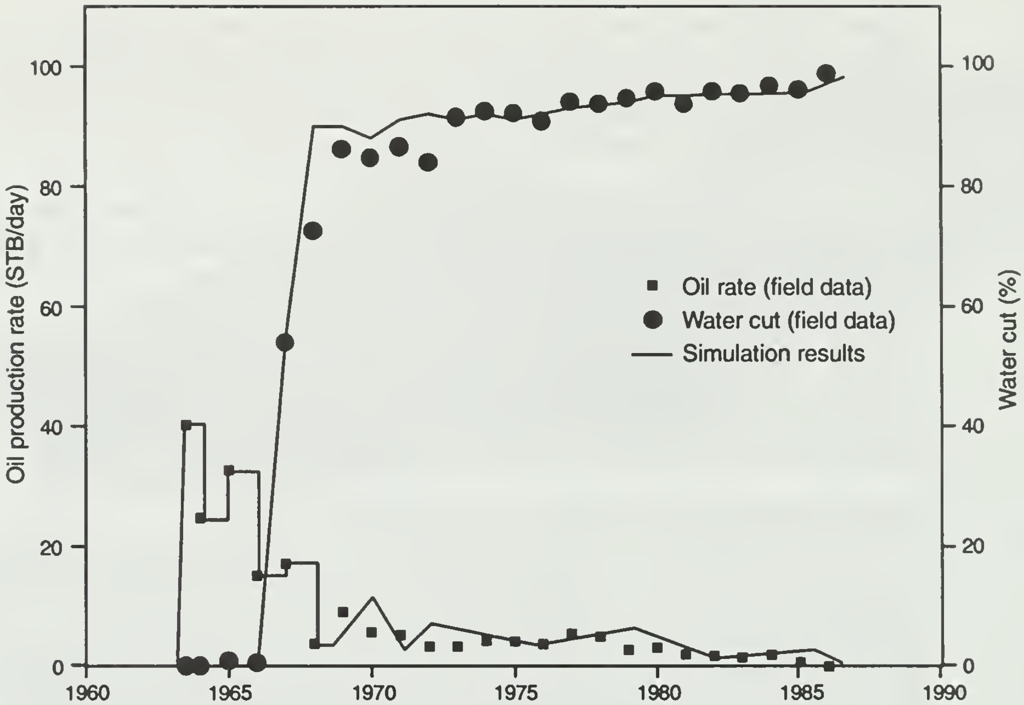


Figure 22 Comparison of simulated values for oil production rates and water cuts for the South Plumfield no. 2 well with actual values through time.

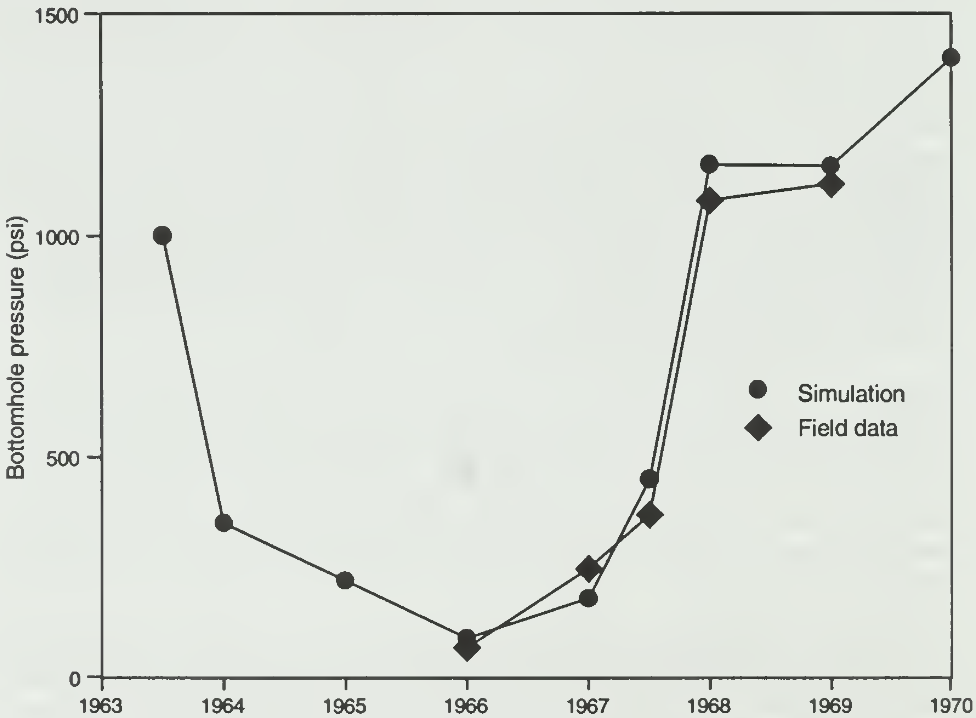


Figure 23 Comparison between observed and calculated field pressure at the Plumfield no. 2 well.

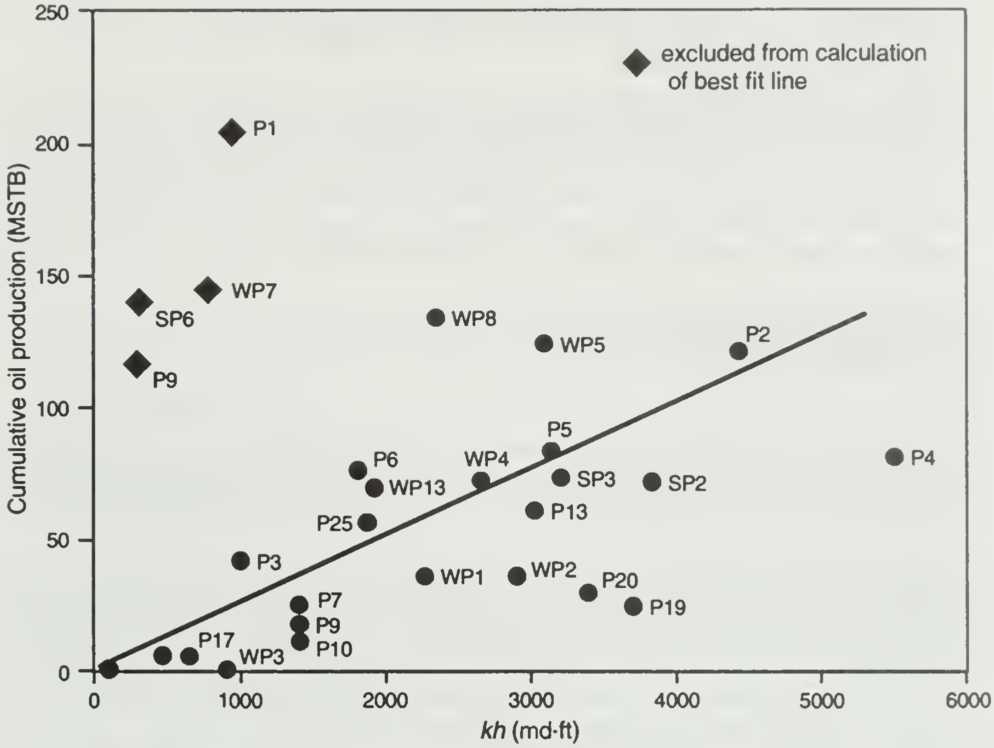


Figure 24 Permeability–thickness value (*kh*) related to cumulative oil production of the Plumfield lease.

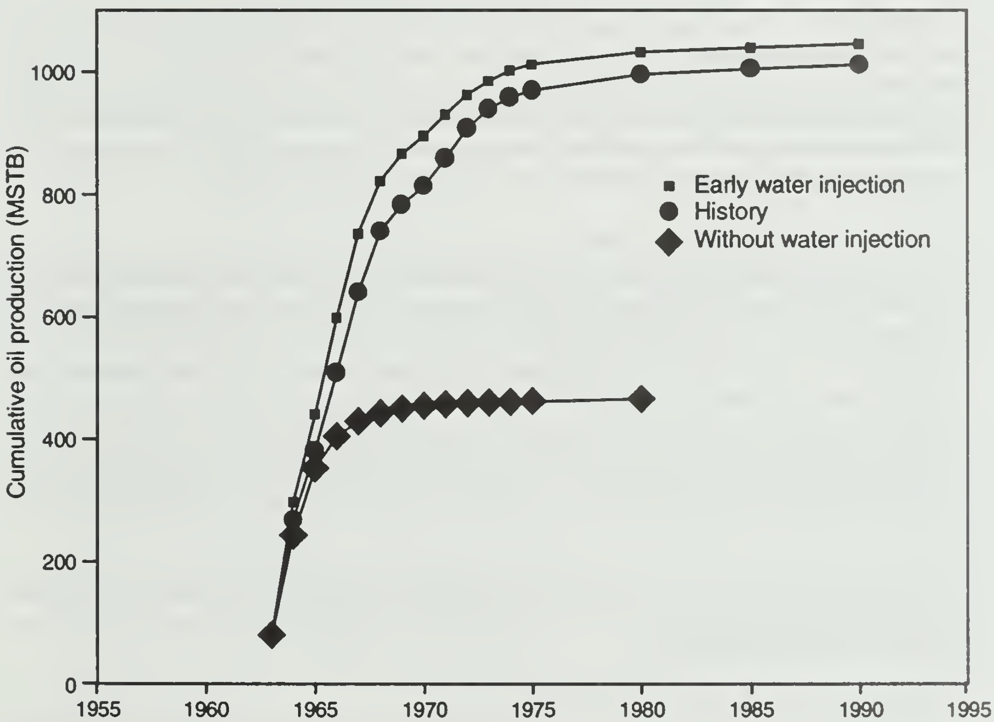


Figure 25 Comparison of historical and alternative (predicted) waterflood oil recovery performance.

Oil Recovery Factor and Unrecovered Mobile Oil in the Plumfield Lease

Total production from June 1963 to February 1992 was 1,963,955 barrels of oil. With an estimated OOIP of 4.56 MMSTB, the ultimate oil recovery is calculated to be 43.07%. If an average residual oil saturation of 22% (from core analysis) were used, the amount of unproduced mobile oil would be 633 MSTB, which is about 14% of the OOIP. This estimated amount represents bypassed oil that can be targeted for recovery through improved waterflooding and, possibly, infill drilling.

FUTURE DEVELOPMENT OPPORTUNITIES IN THE PLUMFIELD LEASE

The simulation results showed that the waterflood project in the Plumfield unit achieved a good overall areal sweep efficiency in the upper sand layer. The vertical sweep efficiency was hampered, however, by vertical heterogeneities. Most of the unrecovered mobile oil is in the lower, less permeable part of the reservoir.

The remaining oil in place (ROIP) is estimated to be 2,596 MSTB (about 57% of the OOIP). It is also estimated that 24% of the ROIP (633 MSTB) could be bypassed in regions of low permeability and small-scale heterogeneities. Among the advanced improved oil recovery methods that can be considered are (1) targeted infill drilling; (2) profile modification with cross-linked polymer, foams, or polymer floods (Schoeling et al. 1989); and (3) enhanced oil recovery methods such as alkaline, alkaline-polymer, surfactant, and microbial floods. The best recovery method for a particular reservoir depends on its predicted performance and economics. Targeted infill drilling is feasible if pockets of bypassed oil can be identified.

As interpreted from the present level of reservoir descriptions, the bulk of the moveable oil is in the lower zone, where the average permeability is lower. Carefully planned tracer tests throughout the field may help to reveal areas that are unswept or poorly swept. The quantity of bypassed oil would have to economically justify the expense of new wells. Studies (US DOE 1991) have shown that oil recovery from EOR projects is generally inversely related to well spacing. When well spacing is decreased by infill drilling, oil recovery increases in many cases.

The use of polymers to plug swept zones may be necessary to recover mobile oil from unswept regions. A problem in applying polymers or their cross-linked varieties in unswept regions is that no distinct permeability barrier delineates the more permeable top area from the less permeable zone below. Permeability declines gradually from top to bottom, particularly in wells containing a sedimentary sequence that coarsens upward. The use of ordinary polymers or cross-linked polymers to improve the sweep efficiency of the lower layer is restricted to the vicinity of the well bores for economic reasons. In the interwell regions, where the bypassed oil resides chiefly in the lower layer, injected water may return to higher permeability strata.

Compared with polymers, the use of microorganisms as profile modification agents, called microbial enhanced oil recovery (MEOR), may be an advantageous alternative for the following reasons.

- The comparatively low cost of MEOR application makes it attractive, especially for stripper oil production.

- Microbial transport is facilitated in regions of higher water saturation and larger pore openings, and it is not limited to the well bore region (Schoeling et al. 1989, Tanner et al. 1991). The expectation is that injected microbes will follow aqueous solutions to regions with higher permeability. Consequently, biomass and

biopolymers should act to reduce the permeability of a reservoir in precisely those zones where action is most needed.

- Depending on the type of nutrients injected and the type of microbes injected or stimulated, metabolic products formed by the microbes, including CO_2 and surfactants, also can improve oil recovery.

SUMMARY AND CONCLUSIONS

- The Plumfield leases of the Zeigler Field, which encompass 500 acres, have produced approximately 2 million barrels of oil from 30 wells during 29 years. The reservoir comprises three narrowly connected and slightly overlapping offshore marine sandstone bars in the Mississippian Aux Vases Formation.

- Historical reservoir management practices at Zeigler Field included coring almost every well, obtaining detailed DST data, and conducting bottom-hole pressure surveys and production–injection surveillances. Waterflood management was enhanced by adequate surveillance practices, such as bottom-hole pressure surveys and monitoring of the injected and produced streams. Interpretation of data from these surveillances enabled the operators to locate a permeability barrier between wells P18 and P19. This knowledge led to the placement of injectors in the eastern part of the field.

- The Plumfield lease contained an estimated 4.560 MMSTB, of which 43.07% had been produced by February 1992. Only two wells are still pumping, and the daily oil production rate is below 28 BOPD. The waterflood recovery, relatively high for the Aux Vases Formation, is attributable to good reservoir management by the operator. The strategies used in this successful waterflood project should be applicable to other similar reservoirs in Illinois.

- Simulation of other possible reservoir management scenarios showed that placement of two water injectors (Plumfield no. 7 and Plumfield no.15 wells) at the onset of oil production instead a year or so later would have recovered about 1.05% more oil than the historical case of 1.963 million barrels of oil.

- Reserve calculations indicate that about 57% of the OOIP still remains at the Plumfield leases and 14% of the OOIP is probably moveable oil that was bypassed. Results of the reservoir simulation indicate that the bulk of the recovered oil was produced from the uppermost permeable sand. The bypassed lower layer of the reservoir may have the best potential for future oil recovery.

- Future development opportunities at the Zeigler Field include selective plugging of the channelized highly permeable upper sandstone layer(s) with polymers or cross-linked polymers and microbial enhanced oil recovery techniques. Targeted infill drilling, as part of an improved oil recovery project, should also be considered if economic considerations permit. Field-wide tracer tests or other flow unit definition tests are strongly recommended to identify permeability barriers not detected by previous management programs in the field. Improved definition of flow units provides a better understanding of the reservoir architecture and indicates how best to recover the remaining oil through improved oil recovery techniques.

ACKNOWLEDGMENTS

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